

# **SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT**

---

## **Assessment of Available Technology for Control of NO<sub>x</sub>, CO, and VOC Emissions from Biogas-Fueled Engines**

### **Draft Final Report**

**June 2012**

#### **Executive Officer**

Barry R. Wallerstein, D.Env.

#### **Deputy Executive Officer**

Planning, Rule Development, and Area Sources  
Elaine Chang, Dr. PH

#### **Assistant Deputy Executive Officer**

Planning, Rule Development, and Area Sources  
Laki Tisopulos, Ph.D., P.E.

#### **Planning and Rules Manager**

Planning, Rule Development, and Area Sources  
Joe Cassmassi

---

Author:

Kevin Orellana – Air Quality Specialist

Reviewed by:

Gary Quinn, P.E. – Program Supervisor  
William Wong – Principal Deputy District Counsel

Technical Assistance

Alfonso Baez, M.S. – Program Supervisor  
Wayne Barcikowski – Air Quality Specialist

## **TABLE OF CONTENTS**

<b>INTRODUCTION</b>	<b>1</b>
<b>BIOGAS CLEANUP</b>	<b>3</b>
<b>CATALYTIC OXIDATION/SELECTIVE CATALYTIC REDUCTION</b>	<b>9</b>
<b>NOXTECH</b>	<b>13</b>
<b>ALTERNATIVE TECHNOLOGIES</b>	<b>15</b>
<b>COST AND COST EFFECTIVENESS</b>	<b>21</b>
<b>GLOBAL WARMING IMPACTS</b>	<b>35</b>
<b>CONCLUSION</b>	<b>41</b>
 <b>ATTACHMENT A – COST EFFECTIVENESS CALCULATIONS FOR RULE 1110.2 REQUIREMENTS FOR BIOGAS ENGINES</b>	 <b>A-1</b>
 <b>ATTACHMENT B – ORANGE COUNTY SANITATION DISTRICT CATALYTIC OXIDIZER/SCR PILOT STUDY FINAL REPORT, JULY 2011</b>	
 <b>REFERENCES</b>	 <b>R-1</b>

## INTRODUCTION

Rule 1110.2 establishes emission limits of NO<sub>x</sub>, VOC, and CO for stationary, non-emergency gaseous- and liquid-fueled engines, including the 55 engines in this source category, that are fueled by landfill or digester gas (biogas). The emissions from biogas engines amount to approximately 1.3 tons per day of NO<sub>x</sub>, 0.8 tons per day of VOC, and 25.6 tons per day of CO.

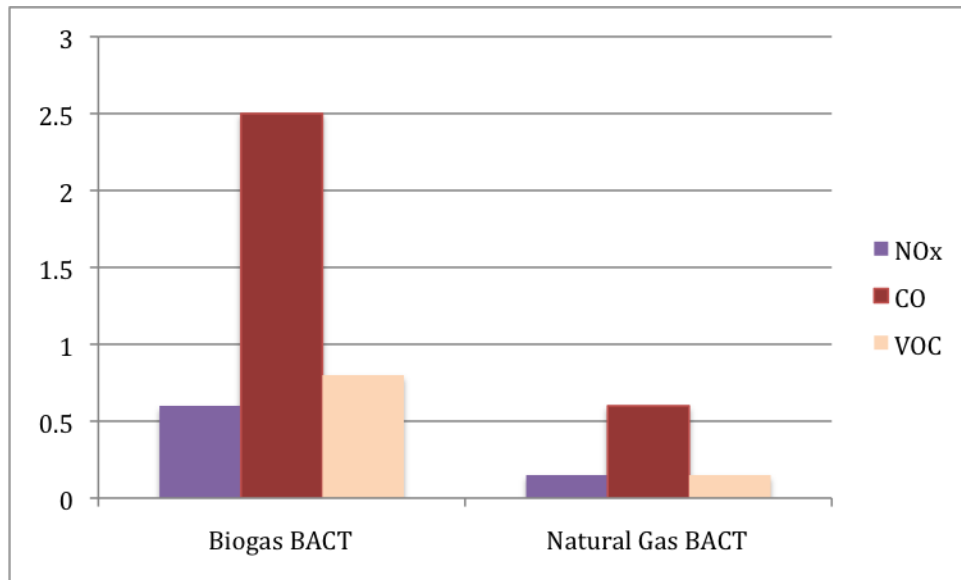
Rule 1110.2 was amended on February 1, 2008 to lower the emission limits of natural gas and biogas engines to BACT levels for NO<sub>x</sub> and VOC and to levels close to BACT for CO. The limits for natural gas engines at or above 500 bhp took effect on July 1, 2010, while those for natural gas engines below 500 bhp took effect on July 1, 2011. Biogas engines were given until July 1, 2012 to comply with the new limits.

**Table 1. Current and Future Biogas Engine Emission Limits (ppmvd @15% O<sub>2</sub>)**

	<b>NO<sub>x</sub></b>	<b>VOC</b>	<b>CO</b>
≥ 500bhp	36 x ECF*	250 x ECF* (digester) 40 (landfill)	2000
< 500 bhp	45 x ECF*	250 x ECF* (digester) 40 (landfill)	2000
<b><i>Future limits</i></b>	<b><i>11</i></b>	<b><i>30</i></b>	<b><i>250</i></b>

\*ECF is the Efficiency Correction Factor

The future emission levels in Table 1 are based on BACT limits for lean-burn natural gas engines, which in g/bhp-hr are 0.15 for NO<sub>x</sub>, 0.6 for CO, and 0.15 for VOC. The current BACT limits for biogas engines are much higher. Expressed in g/bhp-hr, they are 0.6 for NO<sub>x</sub>, 2.5 for CO, and 0.8 for VOC. Figure 1 highlights this difference.



**Figure 1. Biogas vs. Natural Gas BACT in g/bhp-hr**

The BACT limits for lean-burn natural gas engines have been in effect for many years and many installations are complying with these limits by way of oxidation catalysts for CO and VOC control and selective catalytic reduction (SCR) for NOx control.

The amendment and adopting resolutions of Rule 1110.2 in 2008 directed staff to conduct a Technology Assessment to address the availability, feasibility, cost-effectiveness, compliance schedule, and global warming gas impacts of biogas engine control technologies and report back to the Governing Board no later than July 2010. Immediately after the 2008 amendment, staff began work on the Technology Assessment and followed the progress of several technology demonstration projects.

1. *OCSD*. A year-long pilot study utilizing a digester gas cleanup system (non-regenerative) and catalytic oxidation with selective catalytic reduction.
2. *EMWD*. Two selective non-catalytic reduction technologies applied to water and wastewater treatment applications. One technology (NOxTech) was installed at a pumping station with three natural gas-fired engines. The other technology utilizes fuel cells to produce power from digester gas at two of its wastewater treatment facilities.
3. *IEUA*. Fuel cells have been installed at this digester gas facility to eventually replace the IC engines currently installed.

4. *Ox Mountain*. This installation in the Bay Area uses biogas cleanup, catalytic oxidation, and SCR to produce power from landfill gas. The technology is similar to OCSD's in its post combustion after treatment, but uses a regenerative siloxane removal system to clean the landfill gas.

In July 2010, staff presented to the Governing Board an Interim Technology Assessment which summarized the biogas cleanup and biogas engine control technologies to date and the status of on-going demonstration projects. Due to the delays caused by the permit moratorium in 2009, the release of another report was recommended upon the completion of these projects. The Interim Technology Assessment concluded that feasible, cost-effective technology that could support the feasibility of the July 2012 emission limits is available, but that the delay in the demonstration projects would likely necessitate an adjustment to the July 1, 2012 compliance date of Rule 1110.2.

The proposed amendments for Rule 1110.2 provide an adjustment to the July 1, 2012 compliance date. Since July 2010, District staff has received ample evidence in support of the feasibility of biogas engine control technology and the feasibility of the compliance limits to complete the Technology Assessment. This Draft Final Technology Assessment discusses the technologies pertinent to biogas engines for complying with these emission limits.

## **BIOGAS CLEANUP**

For natural gas engines, the use of catalyst after-treatment is an effective method for pollutant control. However, Rule 1110.2 did not lower the emission limits for biogas engines at the same time as natural gas engines because the same catalyst controls for natural gas engines would experience fouling when exposed to the combustion products of biogas. It was learned that the cause of the catalyst fouling was due to a specific impurity in the gas stream. These impurities are now known as siloxanes.

In the 2010 Interim Technology Assessment, the impacts of siloxanes were highlighted and evaluated in terms of facility-specific levels and control costs. The conclusion was that by installing an appropriately designed biogas cleanup system, an engine along with its post-combustion control system can function properly.

A prime concern for many biogas engine operators is the quality of the fuel going into the engines. Biogas, whether coming from a wastewater treatment plant digester or from a landfill, has many impurities, including but not limited to sulfur-containing compounds and siloxanes, that require some sort of treatment. If left untreated, raw biogas can

damage engine components that will result in more maintenance and ultimately, reduced longevity of an engine. Siloxanes crystallize at elevated temperatures and can become deposited even in fuel lines. Upon combustion, siloxanes oxidize and more commonly become deposited on engine parts (pistons, piston sleeves, and valves) as silicon dioxide ( $\text{SiO}_2$ ). As a result, more frequent major maintenance on engines is required so that these deposits can be cleaned up from within the engine. These major repairs involve the removal of the engine head to access the internal valves and piston shafts. Failure to perform this kind of maintenance can result in catastrophic damage to an engine. The pretreatment of biogas is even more critical with the employment of catalyst-based after-treatment technologies downstream from the engines. If left untreated, these siloxane impurities can negatively affect the catalysts. The catalyst active sites can become masked by the deposition of the silica, therefore reducing the efficiency of the entire catalyst for pollutant removal.

Since the release of the Interim Technology Assessment and the installation of several biogas cleanup systems in the basin, it has been established that biogas cleanup cannot consist of siloxane removal only. Depending on the source of the raw biogas, some facilities have biogas profiles that contain varying levels of other pollutants, such as VOCs and sulfur compounds. Also, with the installation of fuel cells and gas turbines operating on biogas in the basin, the fuel specifications for these sophisticated units are extremely stringent for impurities. Biogas entering these systems must be completely cleaned of many impurities to guarantee proper performance.

Some facilities currently have practically no gas cleanup while most others employ some sort of gas cleanup for improved engine maintenance. On the other hand, a few facilities already employ a complete biogas cleanup system for protection of post combustion catalysts or turbines. Many facilities often utilize a typical cleanup system that results in moisture and particulate removal only. The previously mentioned demonstration project at the Orange County Sanitation District (OCSD) utilized the facility's existing compressors and chillers, while relying on a single activated carbon vessel as the sole source for siloxane removal. This digester gas cleaning system (DGCS) was installed (supplied by Applied Filter Technology) to remove contaminants from the digester gas before combustion and the potential for carbon media breakthrough was routinely monitored throughout the pilot study. Depending on the existing level of contaminants, some facilities may have to install complete, skid-mounted gas cleanup systems that can include water and particulate removal filters, sorbent vessels for  $\text{H}_2\text{S}$  and siloxane removal, compressors, chillers, coalescing filters, and vessels for VOC and sulfur species removal if necessary.

As described in the Interim Technology Assessment, there are two types of siloxane removal systems: regenerative and non-regenerative. Regenerative siloxane removal systems do not require constant removal of the sorbent material from the vessels. The vessels are set up in pairs and while the media in the first vessel is regenerated using a heated purge gas the second vessel handles the siloxane cleanup load. The regeneration cycle then switches to the second vessel when it nears its removal efficiency limit, while the first vessel now handles the gas cleanup.

The regenerative siloxane removal system at Ox Mountain Landfill is the only installation that currently uses this type of system for the protection of a post-combustion catalyst on a landfill gas-fired engine. Ox Mountain Landfill is located at Half Moon Bay, CA which is within the Bay Area Air Quality Management District's (BAAQMD) jurisdiction. The landfill gas to energy site (operated by Ameresco) has six GE-Jenbacher engines, each rated at 2677 bhp, that are fired on landfill gas. All six engines have been retrofitted with oxidation catalysts, while one of the engines also has an SCR system. The gas cleanup system with regenerative siloxane removal processes the gas for all the engines. It employs a Temperature Swing Adsorption (TSA) regenerative siloxane removal system manufactured by GE-Jenbacher. Eight pairs of adsorption beds (16 total vessels) using regenerative activated carbon are employed at this installation.  $\text{AlO}_2$  is an alternate media that is used at other locations. Electric coils in the vessel annular space heat the carbon media while clean biogas is flushed through the beds as a purge gas. The purge gas is then combusted by a small, enclosed flare. At Ox Mountain, eight vessels are actively removing impurities while the other eight are being regenerated. The parasitic load of the TSA system is obviously higher when actively heating the vessels, but it is about 5% of the total plant's output. The gas cleanup and oxidation catalyst/SCR was commissioned in 2009 and has shown to be very effective in the removal of siloxanes from the landfill gas. Performance data from 2009 to 2011 shows that the system is removing between 95 and 99 percent of inlet siloxanes (inlet between 7 and 10 ppmv with reported spikes between 25 and 50 ppmv), while no siloxane breakthrough has ever occurred at this facility. The gas is tested periodically, while carbon media and engine samples are also analyzed. Ox Mountain's TSA media requires a complete replacement around every twelve months, but some installations can go longer before media replacement. Every installation will have its own unique gas profile, so the regeneration cycles will be specific for every location and will take start-up time and testing to optimize. The engines at Ox Mountain have also enjoyed the benefit of less frequent maintenance, and can run for much longer between major overhauls.

Non-regenerative siloxane removal systems require periodic replacement of the sorbent material (activated carbon or silica gel) once it is spent. Additionally, the use of two beds is more beneficial in that one bed can still be used while the other is recharged with fresh sorbent and vice versa. These systems are sized to handle the site-specific flow rate into all the facility's biogas engines and the siloxane load. Larger vessels are required for higher flow rate applications and a higher frequency of sorbent replacement is required for biogas streams with higher levels of siloxanes. A redundant dual-bed system enables the handling of intermittent spikes.

The following two tables (Table 2 and Table 3) are updates from the Interim Technology Assessment regarding catalyst performance with the protection of biogas cleanup with non-regenerative siloxane removal systems located both inside and outside of SCAQMD jurisdiction. All of the systems have been successfully operating with varying levels of biogas and the oxidation/SCR catalysts have been protected.

The demonstration project at OCSD has proven that a non-regenerative siloxane treatment system can condition biogas and protect biogas engines and post combustion catalysts. The gas cleanup system removed siloxanes, VOCs, and sulfur compounds effectively without any breakthrough to the engines. An added benefit was realized in that there was a reduction in the engine maintenance due to the cleaner biogas that was being combusted. Furthermore, the result was a cost savings for engine maintenance, increased engine uptime, and longer maintenance intervals. The OCSD demonstration project saved \$43,547 in engine maintenance costs annually with the use and careful monitoring of the gas cleanup system. Additionally, the gas cleanup system from its catalytic oxidizer pilot study in 2007 is still in operation today based on the performance improvements to the engine and the reduced maintenance costs.

With the demonstration project at OCSD completed and the installation at Ox Mountain in its third year, the employment of both regenerative and non-regenerative siloxane removal systems for the protection of post-combustion catalyst has been proven to be feasible. Performance data from both installations demonstrates effective siloxane removal for both digester and landfill gas applications.

**Table 2. Non-Regenerative Siloxane Removal Systems Located in SCAQMD**

<b>System</b>	<b>Type of Biogas</b>	<b>Size (SCFM Biogas)</b>	<b>Combustion Device</b>	<b>Natural Gas Blend in Combustion Device</b>	<b>Catalyst(s)</b>	<b>Startup Year</b>	<b>Operating History</b>	<b>Status</b>	<b>Comments</b>
Orange County Sanitation District	Digester Gas	850	IC Engine	10% Max	Oxidation	2006	Engine operation has been normal	Operating	Similar system tested in pilot study in 2010
Brea Parent 2007, LLC	Landfill Gas	3,000	IC Engine (3)	None	Oxidation	2006	Engine operation has been normal	Operating	Similar system will be used on new turbine plant with Oxidation/SCR catalysts
City of Industry	Landfill Gas	267	IC Engine	73%+	SCR and Oxidation	2005	Seasonal Operation	Use of biogas ended 2007	Methane content too low
UCLA	Landfill Gas	3,472	Gas Turbine	78%+	SCR and Oxidation	1994	Turbine operation has been normal	Operating	
LADWP Scattergood Generating Station	Digester Gas	5,555	Boiler (2)	89%+	SCR and Oxidation	2001	Boilers have been in normal operation	Operating	

**Table 3. Non-Regenerative Siloxane Removal Systems Located Outside of SCAQMD**

<b>System</b>	<b>Type of Biogas</b>	<b>Size (SCFM Biogas)</b>	<b>Combustion Device</b>	<b>Natural Gas Blend in Combustion Device</b>	<b>Catalyst(s)</b>	<b>Startup Year</b>	<b>Operating History</b>	<b>Status</b>	<b>Comments</b>
Carson Cogen (Elk Grove, CA)	Digester Gas	2,500	Gas Turbine	75%	SCR	1996	Turbine operation has been normal	Operating	Digester gas now is further cleaned and transferred via natural gas pipeline to another power plant
Bergen County Utilities Authority (NJ)	Digester Gas	800	IC Engine	None	Oxidation	2002	IC Engine operation was normal	Awaiting Status	
City of Eugene Wastewater Treatment Plant	Digester Gas	240	IC Engine	None	Oxidation	2004	IC Engine operation has been normal	Awaiting Status	

## CATALYTIC OXIDATION/SELECTIVE CATALYTIC REDUCTION

A proven and effective means for CO, VOC, and NO<sub>x</sub> control among natural gas fueled lean-burn engines is catalytic oxidation with selective catalytic reduction (SCR). If the raw biogas is cleaned sufficiently and effectively, there is no danger of fouling any post combustion catalyst by siloxane deposition.

Catalytic oxidation removes CO and VOC upon its contact with the catalyst. Oxidation catalysts contain precious metals that react incoming CO and VOC with oxygen to produce CO<sub>2</sub> and water vapor. Reductions greater than 90% in CO and VOC emissions are typical with this technology.

SCR can be used with lean-burn engines since the higher oxygen concentrations in the exhaust preclude the use of less costly nonselective catalytic reduction (NSCR or three-way catalysts). SCR requires the injection of urea to react with the NO<sub>x</sub> in the engine's flue gas, and is very effective in its removal. The SCR catalyst promotes the reaction of ammonia with NO<sub>x</sub> and oxygen, with water vapor and nitrogen gas being the end products.

The demonstration project at OCSD has shown with certainty that this combination of post combustion systems (oxidation catalyst and SCR) is capable of handling treated biogas combustion exhaust for multi-pollutant control. The District issued a grant to OCSD in 2009 (*SCAQMD Contract #10114*) to support the pilot test study of Engine No. 1 (in Fountain Valley) with a catalytic oxidizer/SCR with digester gas cleanup, and the operation of the pilot study was granted a Permit to Construct/Operate for an Experimental Research Project by SCAQMD (Application Number 497717) in November 2009. The construction and installation of the pilot study equipment commenced in October 2009; the pilot study testing officially began on April 1, 2010 and officially ended on March 31, 2011. A continuous emission monitoring system (CEMS) was used for analysis of NO<sub>x</sub> and CO emissions. The sampling methods for several other pollutants are listed in Table 4.

**Table 4. Sampling Methods for Pollutants in OCSD Pilot Study**

<b>Pollutant</b>	<b>Sampling Method</b>
CO	CEMS, Portable Analyzer, SCAQMD Method 100.1
VOC	SCAQMD Methods 25.1/25.3
NO <sub>x</sub>	CEMS, Portable Analyzer, SCAQMD Method 100.1
Aldehydes	Modified CARB Method 430, SCAQMD Method 323 (Formaldehyde)
Free Ammonia (Ammonia slip)	Modified SCAQMD Method 207.1 and Draeger <sup>®</sup> tubes

The results of the pilot study are as follows:

1. NO<sub>x</sub> emissions averaged around 7 ppmv, well below the proposed rule limit of 11 ppmv by over 35 percent.
2. VOC emissions averaged around 3.6 ppmv, well below the proposed rule limit of 30 ppmv by 88 percent.
3. CO emissions averaged around 7.5 ppmv, well below the proposed rule limit of 250 ppmv by 97 percent.

The maximum VOC level reached was around 5 ppmv, while the maximum CO level reached was 42 ppmv. The results were based on a 15-minute averaging time, per the current rule requirements. There were some NO<sub>x</sub> excursions during the testing period, however, and these accounted for around 4% of the total 15-minute measurement periods, using both valid and invalid data. Exceedances that were attributed to engine start-up (first 30 minutes), operational issues (breakdowns), and system adjustments were excluded and labeled invalid. Only validated data was used to account for the excursions, and these accounted for 0.9% of the total time periods.

OCSD's final report recommended a less restrictive averaging time for biogas engines as a result of the pilot study data. Staff analyzed several possible averaging times to determine an acceptable time period that would address the exceedances without affecting the mass emissions. Using OCSD's 15-minute raw data from its pilot study, several averaging times were evaluated; the results listed in Table 5. Consistent with OCSD's analysis, only validated 15-minute block average data was used (not including

exceedances due to start-up, atypical operating conditions, breakdowns, and system adjustments).

**Table 5. OCSD Pilot Study NO<sub>x</sub> CEMS Data**

Averaging Time (hours)	Number of 15-minute periods >11 ppmv
0.25	182
1	18
2	4
3	4
4	4
6	2
8	0
10	0
12	0
16	0
24	0

Staff found that an 8 hour block-averaging time would address OCSD's exceedances above 11 ppmv. As a result of this analysis, staff is proposing for engines with controls achieving superior performance in terms of reducing emissions, a 12 hour averaging time to be able to comfortably address NO<sub>x</sub> exceedances without affecting the overall mass emissions. This longer averaging time will be extended to CO as well in the Staff proposal. With the results obtained, the OCSD project has demonstrated that this type of control technology can prove effective for meeting the proposed Rule 1110.2 limits.

A consideration that is always taken when applying SCR technology is the potential for ammonia slip when injecting urea into any exhaust gas stream. Ammonia is a toxic compound, and careful control must be taken in order to prevent excess amounts from escaping out of the stack. A limit of 10 ppm was assigned on the project's research permit and the maximum level emitted was 5 ppm during the pilot demonstration. An

important factor when adjusting urea injection rates is ensuring that sufficient amounts of urea are injected in response to the engine's load demand and/or NO<sub>x</sub> level in real time or as close to real time as possible. This is to prevent too much ammonia from escaping out of the stack while simultaneously preventing too little urea from entering the exhaust stream that can result in an increase in NO<sub>x</sub> out of the stack.

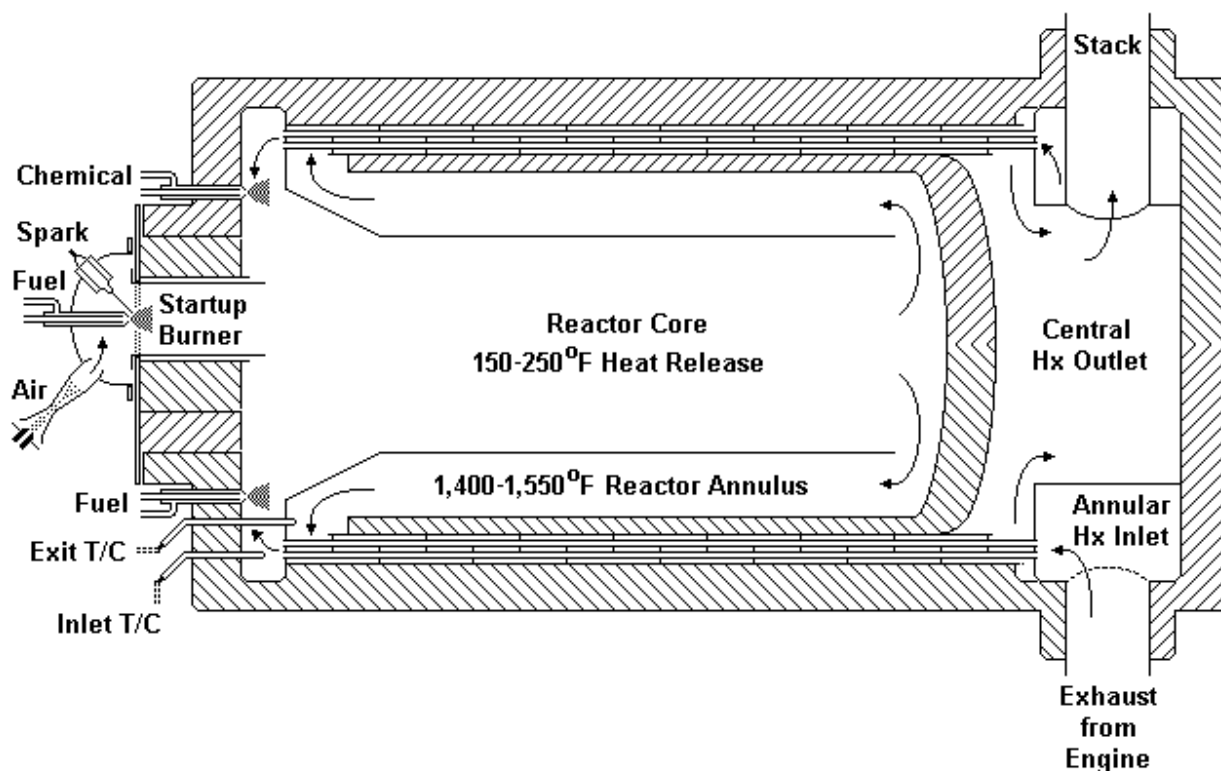
An installation that also uses an oxidation catalyst/SCR technology, but applied to a landfill, is located at the Ox Mountain Landfill in northern California (Figure 2). Ameresco is the facility operator of the biogas engines at this location. One of its six GE-Jenbacher engines on-site was outfitted with both a catalytic oxidizer and SCR system in 2009 and has been operating since. Data that has been obtained from the BAAQMD has shown that the proposed Rule 1110.2 limits are achievable. CEMS data obtained from 2010 shows a consistent performance level that is consistent with OCSD's pilot study. In addition, monthly emission data shows that the proposed emissions limits are being achieved on an average mass per brake horsepower hour basis. The engines experienced some problems soon after startup, but the catalysts have performed effectively since 2009. The oxidation catalyst employs a guard bed upstream of the catalyst to aid in protection from harmful contaminants. The SCR catalyst has not been replaced since start-up, and has yielded efficient NO<sub>x</sub> removal for over 26,000 hours. The NO<sub>x</sub> excursions above 11 ppm throughout the operation of this installation have been attributed to operational problems with the engines, the SCR urea injection system, and monitoring problems. There are many moving parts in a urea injection system and in CEMS equipment, so problems were experienced with plugged nozzles, condensation in sampling lines, sample pump failures, and NO<sub>x</sub> cell failures that led to NO<sub>x</sub> events above 11 ppmv. From Ameresco's experience at Ox Mountain, the oxidation catalyst has experienced decreased performance over time, but not above our proposed compliance limit of 250 ppmv. Engine wear has been suspected as the cause from the catalyst manufacturer, but there has been no evidence of any siloxane breakthrough or siloxane buildup at the oxidation catalysts for any of the six units.



**Figure 2. Ox Mountain's Landfill Gas to Energy Facility in Half Moon Bay, CA**

## **NOXTECH**

NOxTech is another post combustion control technology which provides a selective non-catalytic reduction, does not require gas cleanup, and is capable of achieving multi-pollutant control of NO<sub>x</sub>, VOC, and CO. Engine exhaust gases enter the unit where the temperature is raised by a heat exchanger. The gases then enter a reaction chamber where a small amount of the engine's fuel is added to raise the gas temperature to 1400-1500°F. At this temperature in the reaction chamber, NO<sub>x</sub> reduction can occur using urea injection, while CO and VOC are simultaneously incinerated. The system is designed to handle biogas that is of a lower BTU content than higher BTU natural gas. Natural gas has a BTU of 1,050 BTU per cubic foot, while biogas has a BTU range (depending of the methane content) of approximately 650 BTU per cubic foot.



**Figure 3. NOxTech System**

As mentioned in the Interim Technology Assessment, a full-scale demonstration of this technology occurred at Woodville Landfill starting in 2006, which achieved favorable results. This project operated for four and a half years until the landfill was no longer able to provide sufficient gas to the engine. Two NOxTech units were operated by Southern California Edison (SCE) on diesel engines on Catalina Island from 1995 to 2001. Staff has again requested information from SCE regarding its experience and performance from this demonstration project. In May 2010, Eastern Municipal Water District (EMWD) installed a NOxTech unit at its Mills Pumping Station in Riverside. This site operates three natural gas fired internal combustion engines and the NOxTech unit is capable of handling the exhaust gas streams for multiple engines up to a maximum total rating of 1.5 MW (approximately 2000 bhp, depending on efficiency). While originally designed to treat exhaust gases from biogas engines, EMWD opted to test the NOxTech system with its natural gas-powered engines. The NOxTech system installed downstream of natural gas-powered engines at EMWD experienced some setbacks and was not able to achieve NOx levels that were in compliance with the proposed 11 ppmv

rule limit in 2011 because the system was operating at higher than expected temperatures, resulting in higher than expected thermal NO<sub>x</sub> formation. The combustion of a higher BTU natural gas fuel also burns more quickly, elevating the exhaust temperatures. A variance was granted by the AQMD for the installation and additional testing of an Exhaust Gas Recirculation (EGR) system that is designed to lower the temperature enough to prevent excess NO<sub>x</sub> formation. This enhanced system commenced testing in April 2012 and has shown some promising results. The system is still being optimized to be able to consistently perform at the proposed emission levels. A second NO<sub>x</sub>Tech unit is set to begin construction at the EMWD Temecula facility's digester gas-fired engines later this year.

For engines larger than 1.5 MW, an additional unit is required to handle the flow while a third unit is required for engines larger than 3 MW. Unlike with EMWD, a landfill application would not require an EGR system because there typically is no natural gas backup fuel to run through the unit and because of the lower BTU content of the landfill gas.

A NO<sub>x</sub>Tech system can be a less costly installation than a traditional catalytic oxidation/SCR installation due in large part to the anticipated decreased operations and maintenance (O&M) costs. Periodic sorbent and catalyst replacements are a significant portion of the O&M costs incurred with the operation of a catalytic oxidation/SCR system. While urea injection is still a required component of a NO<sub>x</sub>Tech system, it eliminates the need for any gas cleanup sorbents and post combustion catalysts.

## **ALTERNATIVE TECHNOLOGIES**

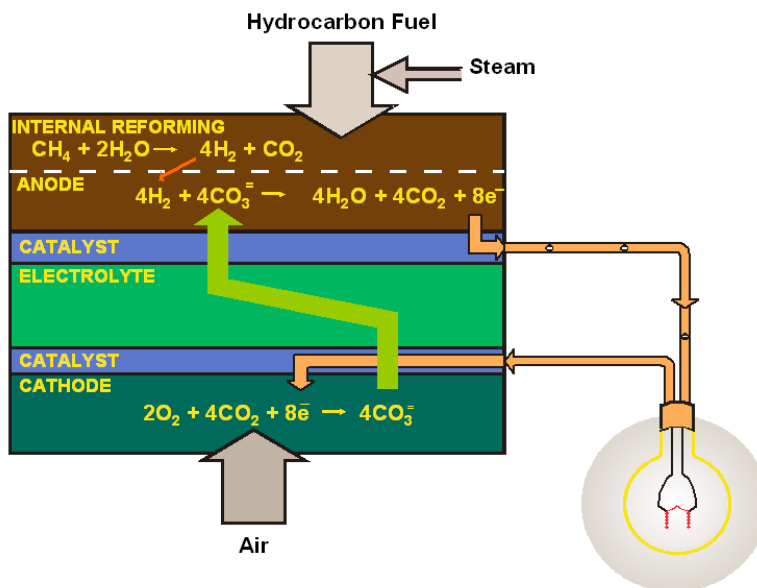
This section provides a brief description on alternative technologies that can be utilized to produce power from biogas with a much lower criteria pollutant emissions profile than that of biogas-fueled IC engines.

### **Fuel Cells**

Fuel cells are an emerging technology capable of producing power with very low pollutant emissions without the utilization of combustion. In fact, fuel cells can produce electricity much more efficiently (between 45-50% efficiency) than combustion-based engines and turbines.

While there are a variety of fuel cell types available, fuel cells for biogas applicability use a molten carbonate cell to create an electrochemical reaction with the inlet biogas at the

anode and oxygen from air at the cathode. Hydrogen is created in a reforming process at the anode, while carbonate ions are created at the cathode. The hydrogen gas reacts with the carbonate ions to produce water and electrons. These electrons flow through an external circuit that produces the electricity for the power plant.



**Figure 4. Fuel Cell Chemistry for Power Generation**

These electrochemical reactions are produced in individual molten carbonate electrolyte stacks. The stacks are modular in design, so the total power production capacity of the generating plant can be tailored to accommodate several fuel cell stacks to meet the desired power output. The heat generated by the fuel cells can also be recovered and used to provide process heat. For instance, the recovered heat can be used to supply heat to a wastewater treatment plant's anaerobic digesters. The fuel cell stacks, however, are sensitive to impurities, so a gas cleanup system is critical to maintain the performance of the fuel cell stacks. Siloxanes, particularly, can foul a fuel cell.

There are many fuel cell installations that run on natural gas, but the activity of digester gas fuel cells in California is significant. There are five installations in the basin located at wastewater treatment plants that are designed to operate on biogas from anaerobic digesters. EMWD has installed a fuel cell power generating facility at the Moreno Valley Regional Water Reclamation Facility and at the Perris Valley facility, while the City of Rialto has also installed a digester gas fuel cell. The City of Riverside has installed a fuel cell system at its wastewater treatment plant and Inland Empire Utilities Agency (IEUA) has completed construction of a 2.8 MW fuel cell plant at its regional plant in Ontario that will begin operating in June 2012. It is the largest fuel cell that will be operating in

the state. The installations at EMWD Moreno Valley and the City of Riverside have encountered some issues with the early design fuel cells. Specifically, the stacks were not producing the electrical output they are rated for. Fuel Cell Energy (FCE), the equipment manufacturer, is currently in the process of replacing the fuel cell stacks at Riverside. EMWD Moreno Valley has restacked the fuel cells and is currently operating. It was found that the cause for the decreased fuel cell stack life was from poisoning by sulfur compounds that the gas cleanup system was not removing sufficiently. FCE now offers to handle the procurement of the gas treatment skid at the time a fuel cell is purchased along with its servicing, as well as aiding in the selection of a third party gas treatment vendor if an operator desires.

Additionally, there are 2 installations in the San Joaquin Valley in Tulare and Turlock. The Turlock installation is currently down because of a lack of digester gas fuel. Two installations are in the Bay Area at Dublin San Ramon (operating) and in San Jose (in the commissioning phase). There is also an installation in Oxnard that is operating well and in San Diego, a group of units will be started up. Fuels cells installed at wastewater treatment plants can take advantage of SGIP funds to offset the capital costs of installation.

An installation under a research permit is also currently underway at OCSd. This unit operates primarily on anaerobic digester gas with the ability to also run on natural gas or a blend of both. It is an experimental installation because the fuel cell operates in conjunction with a hydrogen recovery unit that sends the recovered hydrogen gas to a nearby hydrogen fueling station for use by the public. This project is a collaboration of the United States Department of Energy (DOE), CARB, Air Products and Chemicals, and Fuel Cell Energy. It is expected to operate until 2014 and is intended to demonstrate an alternative energy source while reducing energy costs and reducing emissions.

### Flex Energy

Flex Energy is a system that combines microturbine technology with that of regenerative thermal oxidation to produce power with an ultra low emissions profile and without the necessity of biogas cleanup. The system is capable of taking low BTU content biogas that would be otherwise incombustible by any engine or turbine and diluting it before introducing it to a flameless thermal oxidizer that raises the temperature to destroy VOC and CO. The thermal oxidizer's temperature is also not raised so high as to facilitate the formation of thermal NOx. This process results in the consumption of methane gas without the pollutants from traditional combustion.

An open landfill will produce gas with a more or less constant amount of methane, roughly 50%. The other 50% is typically CO<sub>2</sub>. However, once a landfill ceases to accept municipal solid waste, the amount of gas produced by the landfill will begin to decay gradually. A typical internal combustion engine that runs on landfill gas will struggle if the methane content of the biogas drops below 35-40%. Landfills that produce gas with a methane content lower than what an engine can use will typically send the gas to a flare for combustion. An advantage of the Flex Energy system is that it is capable of handling biogas with a methane content similar to what an engine consumes down to a level that is outside an engine's range of consumption. A Flex Energy system can consume landfill gas well after a landfill closes and well after an engine ceases operation due to the low methane content.

Another advantage with this type of system is that it does not require a fuel cleanup system for siloxanes and other impurities. Like the fuel cells, these systems can be modularly applied, based on the inlet characteristics of the biogas and desired power output.



**Figure 5. Flex Energy FP250 Flex Powerstation**

A pilot study of a Flex Energy installation was recently successfully completed at Lamb Canyon Landfill in Riverside County, CA. A Flex Energy installation is currently collecting data at a landfill in Fort Benning, GA, while approval has been granted for another installation at the Santiago Canyon Landfill in Orange County, set to begin operating later this year.

#### H<sub>2</sub> Assisted Lean Operation (HALO)

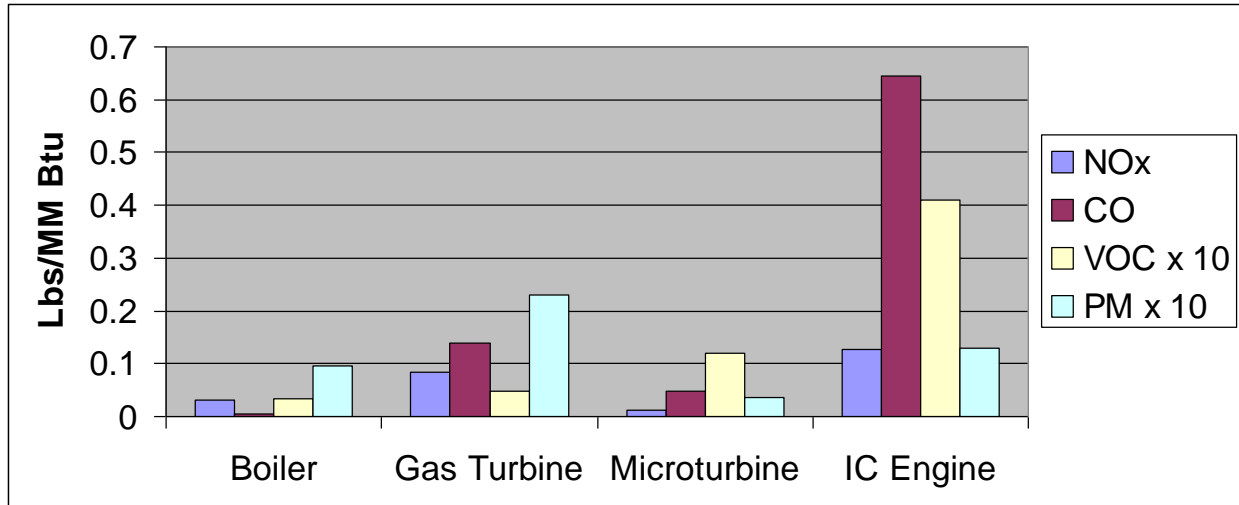
This emerging technology is based on injecting hydrogen gas into the inlet biogas stream before introduction into the engine's combustion chamber. Three to six percent hydrogen gas by mass in the fuel stream is sufficient to extend the lean limit combustion stability for the biogas fuel. Hydrogen's rapid combustion speed, wider combustion limit, and low ignition limit allows for a reduction in the exhaust emissions. There is no need for gas cleanup with the system and it takes up about a cubic meter of space. Some natural

gas is required as feedstock for hydrogen production, but produces additional electrical output and heat that can benefit a biogas facility that utilizes waste heat. The addition of hydrogen reduces hydrocarbon and CO emissions, while the leaner burning fuel lowers the combustion temperature and, therefore, lowers NO<sub>x</sub> formation.

There is no need for gas cleanup or catalytic after-treatment with hydrogen injection and it has been tested by several engine manufacturers on natural gas engines. An added benefit is also an increase in the efficiency of an engine with hydrogen enrichment. A project with the City of San Bernardino Municipal Water Department is expected to commence at the latter part of 2012 on its two, 999 bhp, cogeneration engines.

#### Other Combustion Technologies

Traditional gas turbines, boilers and flares fall under this category. Several landfills in the basin currently employ the use of gas turbines for the combustion of the biogas and also require extensive gas cleanup to protect the turbine blades from siloxane buildup. For example, the Calabasas Landfill operated by Los Angeles County Sanitation District and the Brea-Olinda Landfill currently use turbine technology with gas cleanup for handling landfill produced biogas. The Chiquita Canyon Landfill installation, operated by Ameresco, uses a TSA gas cleanup system similar to the one at Ox Mountain and is currently in the optimization phase. Traditional boilers can also process biogas and currently are being used by both landfills and wastewater treatment plants across the basin. For example, if a facility that operates both engines and boilers elects to shut down its engines, the remaining biogas may be handled by its boilers and any excess can be routed to the facility flare, if necessary. Boilers are less sensitive to impurities, do not require extensive gas cleanup, and can provide waste heat. The last resort for any facility that handles biogas, but cannot combust it because of an insufficient quantity or due to equipment decommissioning, would be to flare. With flaring, a facility can achieve VOC destruction from combustion, while many newer BACT flares achieve low NO<sub>x</sub> emissions. However, there are some possible CO<sub>2</sub> emission impacts from a greenhouse gas perspective and these will be discussed in another section of this document. Figure 6 shows a comparison between source test average emissions among different technologies. Boilers, gas turbines, and microturbines overall have lower emission profiles than IC engines.



**Figure 6. Emissions Comparison Among Different Biogas Electric Generation Technologies**

## **COST AND COST EFFECTIVENESS**

The cost and cost effectiveness analysis for this report relies on real data obtained from OCSD demonstration project. The pilot study demonstration project at OCSD is an example of an achieved in practice installation that has produced favorable results and that is cost effective. This installation used a digester gas cleanup system with a catalytic oxidizer and SCR for post-combustion emissions controls. In OCSD's case, additional structural work was required to support the placement of the catalytic oxidizer and SCR units. An overhead steel platform had to be constructed to support the equipment while allowing vehicle traffic to proceed underneath and to allow for urea deliveries.

The capital costs included the supporting steel necessary for the platform construction, while the annual operating costs included digester gas cleaning media replacement, oxidation catalyst and SCR catalyst replacement, and urea replacement. As a result of the gas cleanup system providing cleaner biogas to the engine, subsequent O&M costs to the engine itself were reduced as well as the frequency of maintenance operations.

The original vendor guarantee was three years for the catalysts, but near the end of the second year of operation (operating under a research permit), the CO emission levels began to rise. The emission levels got to just above 100 ppmv before the catalyst was removed from service and samples were sent for testing (average outlet CO ppm level was 7.5 ppmv during the pilot study). The results confirmed that there was some deactivation of the catalyst evidenced by the presence of a variety of contaminants suspected to originate from the operation of the engine. Although there was an elevation

in the CO emissions, this cannot constitute a catalyst failure since the outlet CO emissions were still in compliance with the proposed CO limit of 250 ppm before removed from service. The oxidation catalysts at Ox Mountain have experienced something similar and yet have been achieving compliance with Staff's proposed CO limit for almost three years. Despite this, a catalyst replacement interval of two years, instead of three years, has been applied as part of the cost analysis described in further detail below.

Emissions and emission reductions are calculated for NO<sub>x</sub>, VOC, and CO. The current emissions are calculated from the current Rule 1110.2 rule limits and permit limits, while the future emissions are calculated from the proposed Rule 1110.2 limits. Permit limits were used for some engines because they were permitted at BACT or have more stringent permit limits than in the current rule. For calculating cost effectiveness, the AQMD uses the Discounted Cash Flow (DCF) model, which takes into consideration both capital cost plus annual operating and maintenance costs. This use of this model is consistent with previous rulemaking proposals and past control measures because it links the cost of the project with its environmental benefits. The equipment is given a twenty year life and a 4% interest rate. The calculated present worth value (PWV) is then divided by the summation of the emission reductions over the length of the project (20 years). The emission reductions for CO are discounted by one seventh because of its ozone-formation potential is approximately one seventh from that of NO<sub>x</sub>.

The 2008 Interim Technology Assessment provided preliminary cost information for a non-regenerative siloxane removal system with oxidation catalyst and SCR, based on OCSD's pilot study cost estimates as the project was beginning. Table 6 provides a comparison between the cost estimates from the Interim Report and those obtained from OCSD's Final Report on its pilot study.

**Table 6. Comparison of OCSD's Costs for Pilot Study Installation and Operation**

	Interim Report	Final Report
Installed Equipment, \$	1,265,000	1,989,529
<i>Equipment minus Catalyst, \$</i>	<i>1,096,000</i>	<i>1,875,129</i>
<i>Catalyst Cost, \$</i>	<i>169,000</i>	<i>114,400</i>
Project Management & Installation Supervision, \$	285,000	298,429
<b>Total Initial Investment, \$</b>	<b>1,550,000</b>	<b>2,287,958</b>
Sorbent Replacement, \$/yr	62,000	40,000
Catalyst Replacement, \$/yr (3 year replacement)	56,000	38,133
Reactant, \$/yr	15,238	18,900
Reduced Power Production, \$/yr	2,363	1,200
Equipment Maintenance, \$/yr	-7,440	-30,147
<b>Total Annual Cost, \$</b>	<b>128,161</b>	<b>58,950</b>
<b>Present Value of 20-yr Cost, \$</b>	<b>3,360,916</b>	<b>3,089,089</b>
NOx Reductions	15.18	10.7
VOC Reductions	2.20	14.6
CO Reductions	0	64.9
<b>Cost Effectiveness (\$/ton NOx+VOC+CO/7)</b>	<b>11,100</b>	<b>4,500*</b>
<b>\$/kW-hr</b>	<b>0.08</b>	<b>0.01</b>

\*This figure is based on permit-specific limits that are lower than the current Rule 1110.2 limits and on 6,000 annual operating hours.

The actual capital costs were higher than was estimated in the Interim Report, but the operation and maintenance costs were actually lower due to the reduced engine maintenance and emission fee credits from the lower emissions. The calculated cost effectiveness of OCSD's 3471 bhp engine and based on the Final Report is \$4,500 per ton of NOx, VOC, and CO/7. OCSD's permit limits for its demonstration project engine are 45ppmv NOx, 209 ppmv VOC, and 590 ppmv CO. Some facilities such as OCSD use the efficiency correction factor (ECF) to operate at a slightly higher NOx and/or VOC limit, for example.

The installation and operating costs for OCSD's system were scaled across a series of varying digester gas engine sizes representative of the current population. OCSD's cost effectiveness was calculated based on 6,000 annual operating hours for the pilot study. The cost effectiveness for this analysis is based on 8,000 operating hours. 8,000 hours was used as a typical usage level for the engines analyzed for the Interim Report. Emissions reductions are calculated from the current Rule 1110.2 rule and permit limits to the proposed Rule 1110.2 limits. Table 7 summarizes these results for digester gas at the base level. The base level assumes a catalyst replacement every two years and the

sorbent costs from the pilot study. The cost effectiveness range for digester gas is between \$1,700 and \$3,500 per ton of NO<sub>x</sub>, VOC, and CO/7.

**Table 7. Base Level Cost Effectiveness for Digester Gas Engines Based on OCSD's Actual Costs**

BHP	4200	3471	1600	1000	500	250
<b>Installed Equipment, \$</b>	<b>2,240,791</b>	<b>1,989,529</b>	<b>1,230,965</b>	<b>921,665</b>	<b>602,807</b>	<b>395,072</b>
<i>Equipment minus Catalyst, \$</i>	2,102,364	1,875,129	1,178,231	888,707	586,328	386,832
<i>Catalyst Cost, \$</i>	138,427	114,400	52,734	32,959	16,479	8,240
Project Management & Installation Supervision, \$	361,107	298,429	137,565	85,978	42,989	21,494
<b>Total Initial Investment, \$</b>	<b>2,601,898</b>	<b>2,287,958</b>	<b>1,368,529</b>	<b>1,007,643</b>	<b>645,796</b>	<b>416,566</b>
Sorbent Replacement, \$/yr	48,401	40,000	18,438	11,524	5,762	2,881
Catalyst Replacement, \$/yr (every 2 yr)	69,213	57,200	26,367	16,479	8,240	4,120
Reactant, \$/yr	22,869	18,900	8,712	5,445	2,723	1,361
Reduced Power Production, \$/yr	2,859	1,200	1,089	681	340	170
Equipment Maintenance, \$/yr	-36,479	-30,147	-13,897	-8,685	-4,343	-2,171
<b>Total Annual Cost, \$</b>	<b>106,865</b>	<b>87,153</b>	<b>40,710</b>	<b>25,444</b>	<b>12,722</b>	<b>6,361</b>
<b>Present Value of 20-yr Cost, \$</b>	<b>4,054,188</b>	<b>3,472,367</b>	<b>1,921,783</b>	<b>1,353,427</b>	<b>818,688</b>	<b>503,012</b>
NO <sub>x</sub> Reduction, tpy	12.6	10.5	4.8	3	1.5	1
VOC Reduction, tpy	29	24	11.1	6.9	3.5	1.7
CO Reduction, tpy	538.9	445.4	205.3	128.3	64.2	32.1
CO Reduction/7, tpy	77.0	63.6	29.3	18.3	9.2	4.6
<b>Cost Effectiveness, \$ per ton of NO<sub>x</sub>+VOC+CO/7</b>	<b>1700</b>	<b>1800</b>	<b>2100</b>	<b>2400</b>	<b>2900</b>	<b>3500</b>
<b>\$/kW-hr</b>	<b>0.008</b>	<b>0.009</b>	<b>0.010</b>	<b>0.012</b>	<b>0.014</b>	<b>0.017</b>

OCSD's actual equipment costs (gas cleanup, oxidation catalyst, SCR, platform) and operating costs (with catalyst change outs every two years) were also applied to landfill gas engines to determine their cost effectiveness. The equipment costs were increased to account for the higher inlet gas volume per BTU supplied to the engine. The cost effectiveness range for landfill gas is between \$2,300 and \$2,900 per ton of NO<sub>x</sub>, VOC, and CO/7. The base level cost effectiveness for this analysis is based on 8,000 operating hours and is summarized in Table 8.

**Table 8. Base Level Cost Effectiveness for Landfill Gas Engines Based on OCSD's Actual Costs**

BHP	4200	3471	2700	2000	1500
<b>Installed Equipment, \$</b>	<b>2,345,061</b>	<b>2,082,529</b>	<b>1,781,763</b>	<b>1,479,753</b>	<b>1,239,133</b>
<i>Equipment minus Catalyst, \$</i>	<i>2,206,634</i>	<i>1,968,129</i>	<i>1,692,774</i>	<i>1,413,835</i>	<i>1,189,695</i>
<i>Catalyst Cost, \$</i>	<i>138,427</i>	<i>114,400</i>	<i>88,989</i>	<i>65,918</i>	<i>49,438</i>
Project Management & Installation Supervision, \$	361,107	298,429	232,140	171,956	128,967
<b>Total Initial Investment, \$</b>	<b>2,706,168</b>	<b>2,380,958</b>	<b>2,013,903</b>	<b>1,651,708</b>	<b>1,368,100</b>
Sorbent Replacement, \$/yr	48,401	40,000	31,115	23,048	17,286
Catalyst Replacement, \$/yr (every 2 yr)	69,213	57,200	44,494	32,959	24,719
Reactant, \$/yr	22,869	18,900	14,702	10,890	8,168
Reduced Power Production, \$/yr	1,664	1,200	1,069	792	594
Equipment Maintenance, \$/yr	-36,479	-30,147	-23,451	-17,371	-13,028
<b>Total Annual Cost, \$</b>	<b>105,669</b>	<b>87,153</b>	<b>67,930</b>	<b>50,319</b>	<b>37,739</b>
<b>Present Value of 20-yr Cost, \$</b>	<b>4,142,210</b>	<b>3,565,367</b>	<b>2,937,073</b>	<b>2,335,538</b>	<b>1,880,972</b>
NOx Reduction, tpy	12.6	10.5	8.1	6	4.5
VOC Reduction, tpy	1.3	1.1	0.8	0.6	0.5
CO Reduction, tpy	538.9	445.4	346.4	256.6	192.5
CO Reduction/7, tpy	77.0	63.6	49.5	36.7	27.5
<b>Cost Effectiveness, \$ per ton of NOx+VOC+CO/7 \$/kW-hr</b>	<b>2300</b>	<b>2400</b>	<b>2500</b>	<b>2700</b>	<b>2900</b>
	<b>0.009</b>	<b>0.009</b>	<b>0.009</b>	<b>0.010</b>	<b>0.011</b>

\*The equipment costs were increased by \$93,000 to account for the siloxane cleanup system's processing of a greater gas volume per BTU supplied to the engine

Several stakeholders have expressed concern over the high cost of gas cleanup, primarily to address the removal of siloxanes from the biogas inlet stream. In addition, all facilities have varying levels of impurities in the biogas and some may have to install additional pretreatment for sulfur compounds if the levels are high. Redundant siloxane removal systems are a necessity and must be capable of handling the base siloxane load as well as intermittent spikes. To address these concerns in the cost analysis, Staff analyzed two other scenarios where additional gas treatment contingencies were added to the operational costs. These costs are based on vendor quotes for the full scale of flow rates of all the affected biogas facilities. The media costs were then normalized to obtain "per engine" costs, which were then bracketed to the appropriate engine brake horsepower sizes. The carbon media change-out frequency is dependent on the siloxane level; the higher the siloxane level, the more frequent the media change-out. The cost of the media

is correlated to the media weight relative to the flow rate and vessel size. Staff has assumed a worst case where media change-outs will be required once per month.

On top of this, Staff also included a 20% contingency to the equipment costs to account for any additional gas cleanup required or to account for backpressure considerations in smaller engines or for additional compression and chilling equipment. Vendor supplied equipment costs are in line with the scaled costs from the base scenario for both gas cleanup and catalytic after-treatment. The operating costs are the major contributor to the overall cost of the gas cleanup system. The following two tables (Tables 9 and 10) represent the worst case costs with the additional gas cleanup and the additional 20% equipment cost contingency applied.

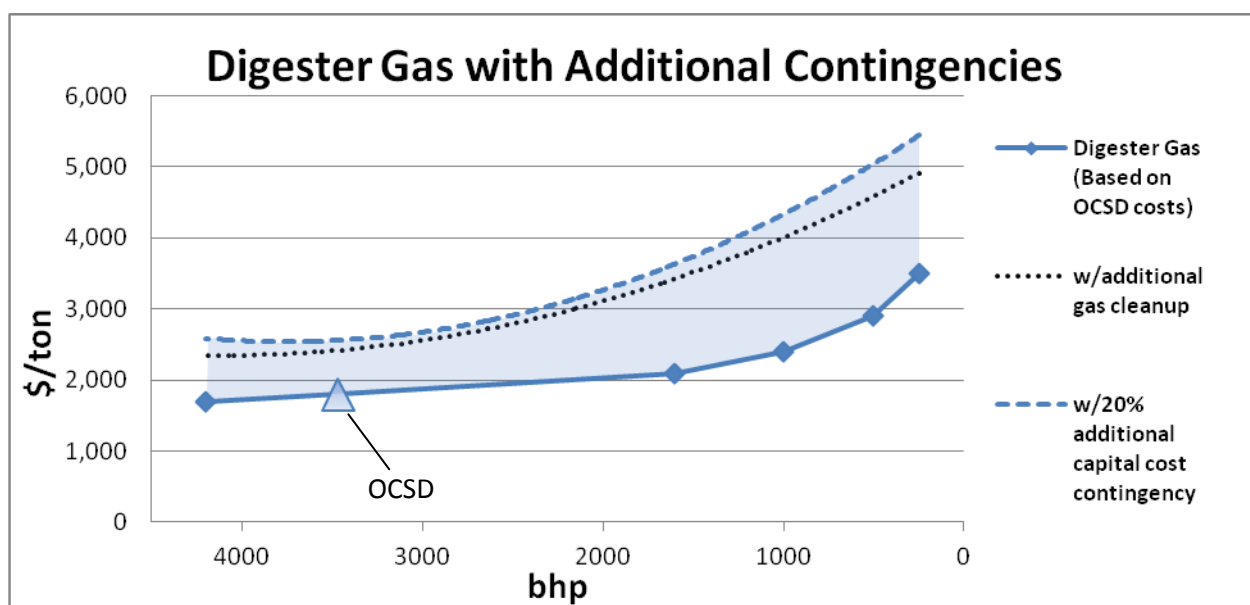
**Table 9. Cost Effectiveness for Digester Gas Engines Based on OCSD's Actual Costs with Additional Contingencies**

BHP	4200	3471	1600	1000	500	250
Installed Equipment, \$	2,240,791	1,989,529	1,230,965	921,665	602,807	395,072
Equipment minus Catalyst, \$	2,102,364	1,875,129	1,178,231	888,707	586,328	386,832
Added Cleanup w/20% contingency	420,473	375,026	235,646	177,741	117,266	77,366
Catalyst Cost, \$	138,427	114,400	52,734	32,959	16,479	8,240
<b>Installed Equipment w/20% contingency, \$</b>	<b>2,661,264</b>	<b>2,364,555</b>	<b>1,466,611</b>	<b>1,099,407</b>	<b>720,073</b>	<b>472,438</b>
Project Management & Installation Supervision, \$	361,107	298,429	137,565	85,978	42,989	21,494
<b>Total Initial Investment, \$</b>	<b>3,022,371</b>	<b>2,662,984</b>	<b>1,604,176</b>	<b>1,185,384</b>	<b>763,062</b>	<b>493,933</b>
Sorbent Replacement, \$/yr	165,600	138,000	69,000	103,500	51,570	12,420
Catalyst Replacement, \$/yr (every 2yr)	69,213	57,200	26,367	16,479	8,240	4,120
Reactant, \$/yr	22,869	18,900	8,712	5,445	2,723	1,361
Reduced Power Production, \$/yr	2,859	1,200	1,089	681	340	170
Equipment Maintenance, \$/yr	-36,479	-30,147	-13,897	-8,685	-4,343	-2,171
<b>Total Annual Cost, \$</b>	<b>224,064</b>	<b>185,153</b>	<b>91,272</b>	<b>117,420</b>	<b>58,530</b>	<b>15,900</b>
<b>Present Value of 20-yr Cost, \$</b>	<b>6,067,395</b>	<b>5,179,213</b>	<b>2,844,560</b>	<b>2,781,121</b>	<b>1,558,484</b>	<b>710,013</b>
NOx Reduction, tpy	12.6	10.5	4.8	3	1.5	1
VOC Reduction, tpy	29	24	11.1	6.9	3.5	1.7
CO Reduction, tpy	538.9	445.4	205.3	128.3	64.2	32.1
CO Reduction/7, tpy	77.0	63.6	29.3	18.3	9.2	4.6
<b>Cost Effectiveness, \$ per ton of NOx+VOC+CO/7</b>	<b>2600</b>	<b>2600</b>	<b>3100</b>	<b>4900</b>	<b>5500</b>	<b>4900</b>
<b>\$/kW-hr</b>	<b>0.012</b>	<b>0.013</b>	<b>0.015</b>	<b>0.024</b>	<b>0.027</b>	<b>0.025</b>

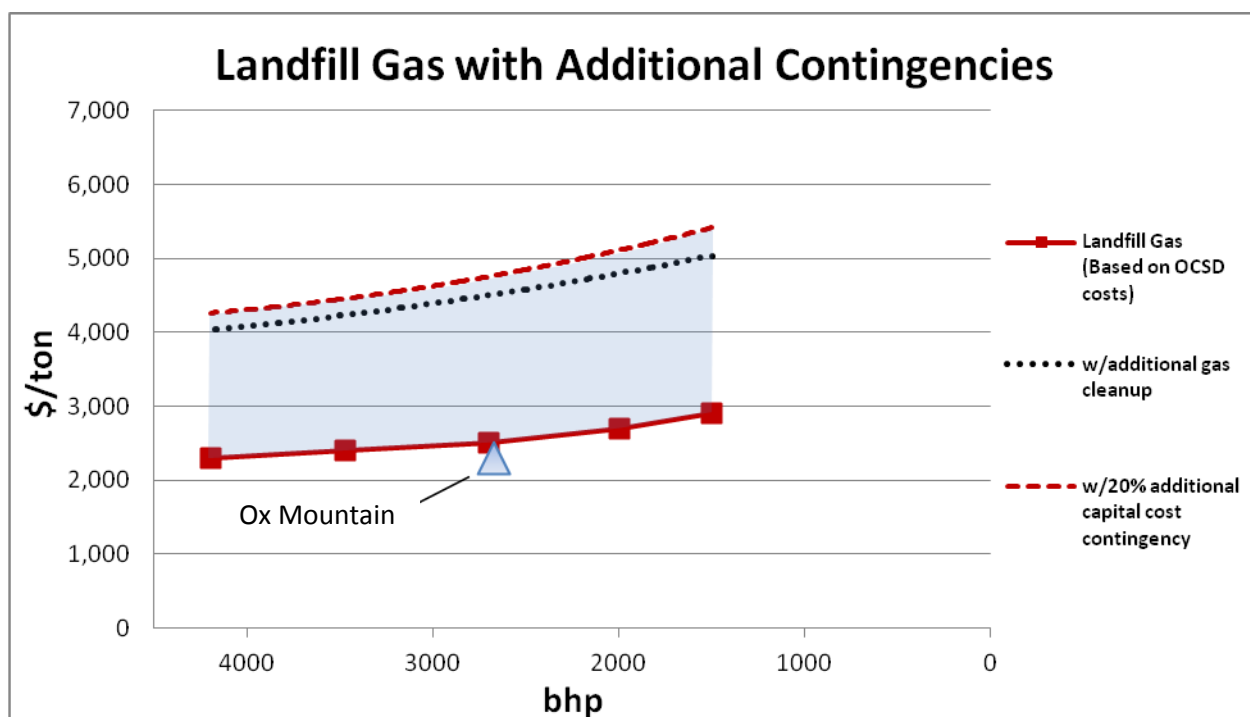
**Table 10. Cost Effectiveness for Landfill Gas Engines Based on OCSD's Actual Costs with Additional Contingencies**

BHP	4200	3471	2700	2000	1500
Installed Equipment, \$	2,345,061	2,082,529	1,781,763	1,479,753	1,239,133
<i>Equipment minus Catalyst, \$</i>	2,206,634	1,968,129	1,692,774	1,413,835	1,189,695
<i>Added Cleanup w/20% contingency</i>	441,327	393,626	338,555	282,767	237,939
<i>Catalyst Cost, \$</i>	138,427	114,400	88,989	65,918	49,438
<b>Installed Equipment w/20% contingency, \$</b>	<b>2,786,388</b>	<b>2,476,155</b>	<b>2,120,318</b>	<b>1,762,520</b>	<b>1,477,072</b>
Project Management & Installation Supervision, \$	361,107	298,429	232,140	171,956	128,967
<b>Total Initial Investment, \$</b>	<b>3,147,495</b>	<b>2,774,584</b>	<b>2,352,458</b>	<b>1,934,475</b>	<b>1,606,039</b>
Sorbent Replacement, \$/yr	276,000	276,000	138,000	207,000	103,500
Catalyst Replacement, \$/yr (every 2yr)	69,213	57,200	44,494	32,959	24,719
Reactant, \$/yr	22,869	18,900	14,702	10,890	8,168
Reduced Power Production, \$/yr	1,664	1,200	1,069	792	594
Equipment Maintenance, \$/yr	-36,479	-30,147	-23,451	-17,371	-13,028
<b>Total Annual Cost, \$</b>	<b>333,268</b>	<b>323,153</b>	<b>174,815</b>	<b>234,270</b>	<b>123,953</b>
<b>Present Value of 20-yr Cost, \$</b>	<b>7,676,607</b>	<b>7,166,233</b>	<b>4,728,196</b>	<b>5,118,211</b>	<b>3,290,558</b>
NOx Reduction, tpy	12.6	10.5	8.1	6	4.5
VOC Reduction, tpy	1.3	1.1	0.8	0.6	0.5
CO Reduction, tpy	538.9	445.4	346.4	256.6	192.5
CO Reduction/7, tpy	77.0	63.6	49.5	36.7	27.5
<b>Cost Effectiveness, \$ per ton of</b>					
<b>NOx+VOC+CO/7</b>	<b>4200</b>	<b>4800</b>	<b>4000</b>	<b>5900</b>	<b>5100</b>
<b>\$/kW-hr</b>	<b>0.016</b>	<b>0.018</b>	<b>0.015</b>	<b>0.022</b>	<b>0.019</b>

The worst case costs, along with the base case costs were plotted on the following two graphs for digester gas and landfill gas (Figure 7 and Figure 8). Since every facility is unique in the flow rate, engine size, and number of engines installed, the bracketed sorbent replacement costs are not necessarily linear. However, there is a sufficient correlation to apply a polynomial regression to each curve (with additional gas cleanup and with 20% additional contingency) and be able to represent them here. The worst case scenario cost effectiveness range for digester gas is from \$2,600 to \$5,500 per ton and from \$4,200 to \$5,900 per ton for landfills.



**Figure 7. Cost Effectiveness for Digester Gas (Catalytic Aftertreatment)**



**Figure 8. Cost Effectiveness for Landfill Gas (Catalytic Aftertreatment)**

Cost data was also received from the Bay Area AQMD for the installation at Ox Mountain Landfill's 2,677 bhp engine with regenerative temperature swing adsorption (TSA) gas cleanup, oxidation catalyst, and SCR (Table 9). There are six total engines at that facility. Cost effectiveness was calculated from SCAQMD rule limits to the proposed rule limits, operating 8,000 hours per year. There may be an increased capital cost for a regenerative TSA system, but the total gas cleanup cost was divided by 6 to arrive at the per-engine estimate. The cost effectiveness for Ox Mountain is within the range of Staff's estimates for the proposed amendments (Figure 8). The annual costs presented here do not reflect any credit taken for reduced engine maintenance, so the actual operating costs may be lower than those in Table 11. From Ox Mountain's experience, the sorbent change-outs could be longer than once every twelve months.

**Table 11. Cost Effectiveness of Landfill Installation with Regenerative Gas Cleanup, Oxidation Catalyst, and SCR**

<i>Capital Costs*</i>	
TSA System, \$	271,544
TSA Installation, \$	91,480
TSA Flare, \$	25,105
TSA Flare Install, \$	6,699
SCR System, \$	46,218
SCR Install, \$	28,960
Ox Cat System, \$	38,218
Ox Cat Install, \$	28,377
CEMS, \$	170,165
CEMS Install, \$	20,080
Design & Eng (3.4% of equip), \$	18,742
Const & Comm (8% of equip), \$	44,100
<b>Total Installed Cost, \$</b>	<b>789,688</b>
 <i>Operating Costs</i>	
TSA, \$	14,000
Flare, \$	2,917
CEMS, \$	34,600
SCR, \$	51,394
Ox Cat, \$	12,514
Labor, \$	10,000
Electricity, \$	8,790
<b>Total Annual Op Costs, \$</b>	<b>134,215</b>
 <b>PWV (20 yrs @4%), \$</b>	 <b>2,613,673</b>
 NOx Reduction, tpy	 8.1
VOC Reduction, tpy	0.8
CO Reduction, tpy	343.5
CO Reduction/7, tpy	49.1
<b>Cost Effectiveness, \$ per ton of</b>	
<b>NOx+VOC+CO/7</b>	<b>2,300</b>
<b>\$/kW-hr</b>	<b>0.008</b>

\*TSA system costs were divided by 6 to reflect a per-engine basis estimate

#### NOxTech Cost Effectiveness

Cost information was also obtained from NOxTech based on its installation at Eastern Municipal Water District's (EMWD) Mills Station. EMWD also submitted cost data

reflecting the additional costs to install an EGR unit as it is currently undergoing further testing for its demonstration. For the cost effectiveness analysis, EMWD's additional costs amounted to a contingency for the installation costs of the NOxTech unit with EGR and its associated equipment. The addition of an EGR system is not anticipated to be required on landfill gas installations, so the contingency will be applied only to digester gas engines. The total amounts of contingency cost experienced by EMWD are not expected to be incurred by subsequent users. Table 11 shows the base level based on costs submitted by NOxTech for digester gas engines, while Table 12 shows the additional contingencies. Table 13 shows the base level only for landfill gas engines.

**Table 11. Base Level Cost Effectiveness for Digester Gas Engines Based on NOxTech Costs**

BHP	4200	3471	1600	1350	1000	500	250
<b>Installed Equipment, \$</b>							
Equipment Cost, \$	960,000	800,000	400,000	400,000	400,000	400,000	400,000
Installation Cost, \$	250,000	200,000	100,000	100,000	100,000	100,000	100,000
Project Management & Installation Supervision, \$	31,742	26,452	13,226	13,226	13,226	13,226	13,226
<b>Total Initial Investment, \$</b>	<b>1,241,742</b>	<b>1,026,452</b>	<b>513,226</b>	<b>513,226</b>	<b>513,226</b>	<b>513,226</b>	<b>513,226</b>
Reactant, \$/yr	37,952	31,365	14,458	12,199	9,036	4,518	2,259
Reduced Power Production, \$/yr	68,365	56,499	26,044	21,975	16,277	8,139	4,069
Equipment Maintenance, \$/yr	16,000	16,000	8,100	8,100	8,100	8,100	8,100
<b>Total Annual Cost, \$</b>	<b>122,318</b>	<b>103,864</b>	<b>48,602</b>	<b>42,274</b>	<b>33,414</b>	<b>20,757</b>	<b>14,428</b>
<b>Present Value of 20-yr Cost, \$</b>	<b>2,904,042</b>	<b>2,437,965</b>	<b>1,173,728</b>	<b>1,087,724</b>	<b>967,319</b>	<b>795,312</b>	<b>709,308</b>
NOx Reduction, tpy	12.6	10.5	4.8	4.1	3	1.5	1
VOC Reduction, tpy	29	24	11.1	9.3	6.9	3.5	1.7
CO Reduction, tpy	538.9	445.4	205.3	173.2	128.3	64.2	32.1
CO Reduction/7, tpy	77.0	63.6	29.3	24.7	18.3	9.2	4.6
<b>Cost Effectiveness, \$ per ton of NOx+VOC+CO/7 \$/kW-hr</b>	<b>1200</b>	<b>1200</b>	<b>1300</b>	<b>1400</b>	<b>1700</b>	<b>2800</b>	<b>4900</b>
	<b>0.006</b>	<b>0.006</b>	<b>0.006</b>	<b>0.007</b>	<b>0.008</b>	<b>0.014</b>	<b>0.025</b>

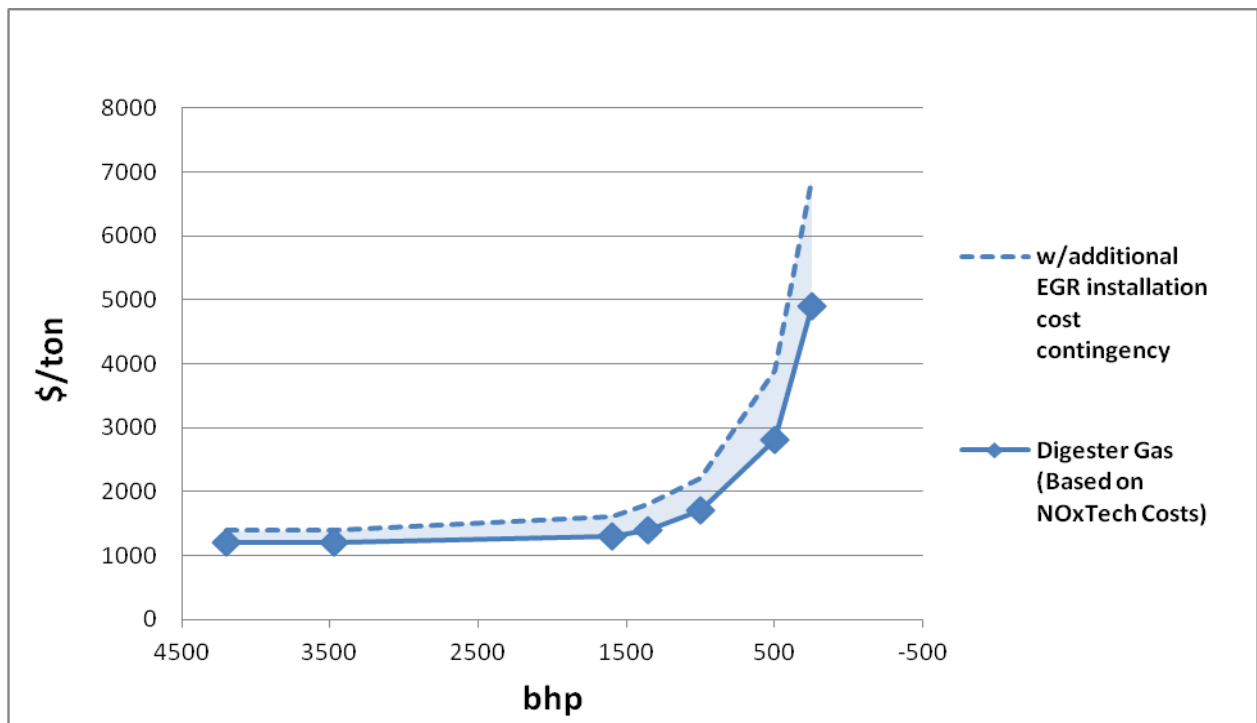
**Table 12. Cost Effectiveness for Digester Gas Engines Based on EMWD's Costs  
with Additional Contingencies**

BHP	4200	3471	1600	1350	1000	500	250
<b>Installed Equipment, \$</b>							
<i>Equipment Cost, \$</i>	<i>960,000</i>	<i>800,000</i>	<i>400,000</i>	<i>400,000</i>	<i>400,000</i>	<i>400,000</i>	<i>400,000</i>
<i>Installation Cost, \$</i>	<i>250,000</i>	<i>200,000</i>	<i>100,000</i>	<i>100,000</i>	<i>100,000</i>	<i>100,000</i>	<i>100,000</i>
<i>Installation Cost Contingency, \$</i>	<i>300,000</i>	<i>300,000</i>	<i>300,000</i>	<i>300,000</i>	<i>300,000</i>	<i>300,000</i>	<i>300,000</i>
Project Management & Installation Supervision, \$	31,742	26,452	13,226	13,226	13,226	13,226	13,226
<b>Total Initial Investment, \$</b>	<b>1,541,742</b>	<b>1,326,452</b>	<b>813,226</b>	<b>813,226</b>	<b>813,226</b>	<b>813,226</b>	<b>813,226</b>
Reactant, \$/yr	37,952	31,365	14,458	12,199	9,036	4,518	2,259
Reduced Power Production, \$/yr	68,365	56,499	26,044	21,975	16,277	8,139	4,069
Equipment Maintenance, \$/yr	16,000	16,000	8,100	8,100	8,100	8,100	8,100
<b>Total Annual Cost, \$</b>	<b>122,318</b>	<b>103,864</b>	<b>48,602</b>	<b>42,274</b>	<b>33,414</b>	<b>20,757</b>	<b>14,428</b>
<b>Present Value of 20-yr Cost, \$</b>	<b>3,204,042</b>	<b>2,737,965</b>	<b>1,473,728</b>	<b>1,387,724</b>	<b>1,267,319</b>	<b>1,095,312</b>	<b>1,009,308</b>
NOx Reduction, tpy	12.6	10.5	4.8	4.1	3	1.5	1
VOC Reduction, tpy	29	24	11.1	9.3	6.9	3.5	1.7
CO Reduction, tpy	538.9	445.4	205.3	173.2	128.3	64.2	32.1
CO Reduction/7, tpy	77.0	63.6	29.3	24.7	18.3	9.2	4.6
<b>Cost Effectiveness, \$ per ton of NOx+VOC+CO/7</b>	<b>1400</b>	<b>1400</b>	<b>1600</b>	<b>1800</b>	<b>2200</b>	<b>3900</b>	<b>6900</b>
<b>\$/kW-hr</b>	<b>0.007</b>	<b>0.007</b>	<b>0.008</b>	<b>0.009</b>	<b>0.011</b>	<b>0.019</b>	<b>0.035</b>

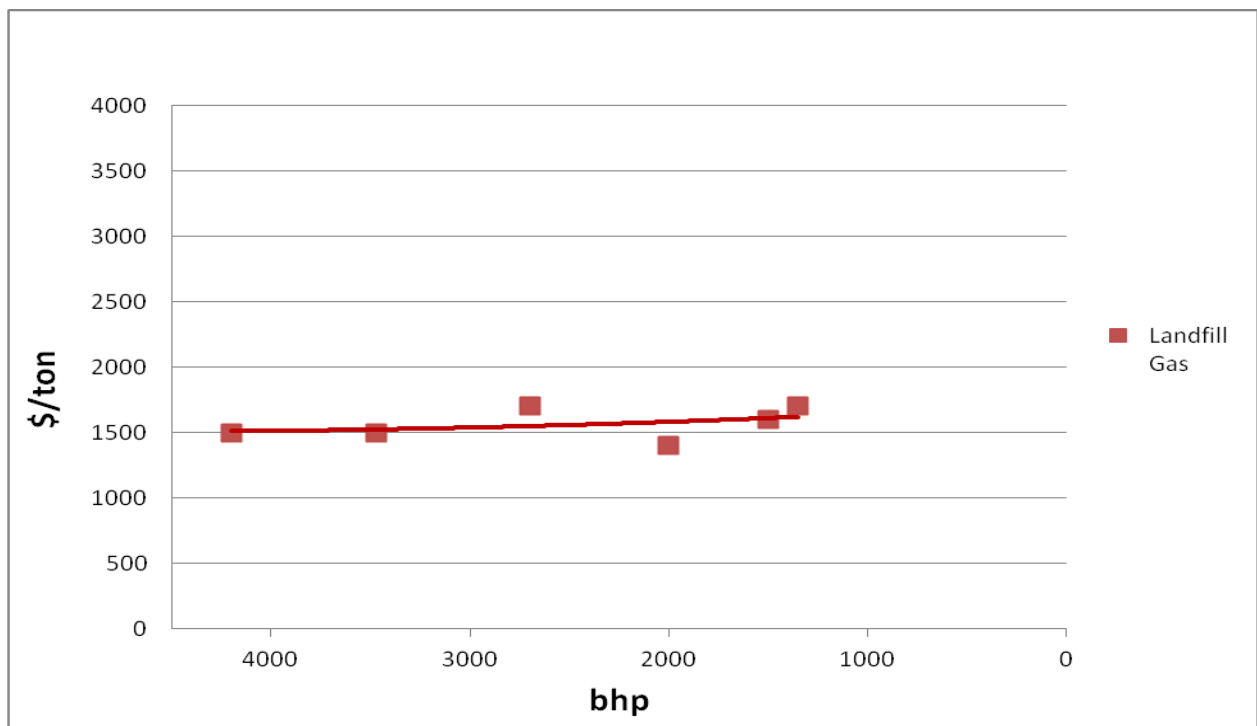
**Table 13. Base Level Cost Effectiveness for Landfill Gas Engines Based on NOxTech Costs**

BHP	4200	3471	2700	2000	1500	1350
<b>Installed Equipment, \$</b>						
<i>Equipment Cost, \$</i>	<i>960,000</i>	<i>800,000</i>	<i>800,000</i>	<i>400,000</i>	<i>400,000</i>	<i>400,000</i>
<i>Installation Cost, \$</i>	<i>250,000</i>	<i>200,000</i>	<i>200,000</i>	<i>100,000</i>	<i>100,000</i>	<i>100,000</i>
Project Management & Installation Supervision, \$	31,742	26,452	26,452	13,226	13,226	13,226
<b>Total Initial Investment, \$</b>	<b>1,241,742</b>	<b>1,026,452</b>	<b>1,026,452</b>	<b>513,226</b>	<b>513,226</b>	<b>513,226</b>
Reactant, \$/yr	37,952	31,365	24,398	18,073	13,554	12,199
Reduced Power Production, \$/yr	53,041	43,834	34,098	25,258	18,943	17,049
Equipment Maintenance, \$/yr	16,000	16,000	16,000	8,100	8,100	8,100
<b>Total Annual Cost, \$</b>	<b>106,993</b>	<b>91,199</b>	<b>74,496</b>	<b>51,430</b>	<b>40,598</b>	<b>37,348</b>
<b>Present Value of 20-yr Cost, \$</b>	<b>2,695,780</b>	<b>2,265,852</b>	<b>2,038,847</b>	<b>1,212,161</b>	<b>1,064,947</b>	<b>1,020,783</b>
NOx Reduction, tpy	12.6	10.5	8.1	6	4.5	4.1
VOC Reduction, tpy	1.3	1.1	0.8	0.6	0.5	0.4
CO Reduction, tpy	538.9	445.4	346.4	256.6	192.5	173.2
CO Reduction/7, tpy	77.0	63.6	49.5	36.7	27.5	24.7
<b>Cost Effectiveness, \$ per ton of NOx+VOC+CO/7 \$/kW-hr</b>	<b>1500</b>	<b>1500</b>	<b>1700</b>	<b>1400</b>	<b>1600</b>	<b>1700</b>
	<b>0.006</b>	<b>0.006</b>	<b>0.007</b>	<b>0.005</b>	<b>0.006</b>	<b>0.007</b>

Figures 9 and 10 illustrate the cost effectiveness for NOxTech graphically. For digester gas, the shaded band reflects the possible contingency costs in relation to the base level costs. For landfills, the modular nature of the base level equipment costs from NOxTech result in a slightly less than linear representation. However, there is sufficient correlation to apply a regression that results in the curve illustrated in Figure 10.



**Figure 9. Cost Effectiveness for Digester Gas Based on NOxTech Costs with Additional Contingencies**



**Figure 10. Cost Effectiveness for Landfill Gas Based on NOxTech Costs**

The cost effectiveness estimates presented here are within the range of cost effectiveness estimates presented to the Governing Board for past rulemakings. Digester gas and landfill gas engines of all sizes are shown to be cost-effective for all scenarios. The dollars per kilowatt-hour estimates (which assume a 97% generator efficiency) also show that the addition of emission controls is cheaper than the cost of electricity from the grid which runs about 8 to 10 cents per kilowatt-hour.

## **GLOBAL WARMING IMPACTS**

The Adopting Board Resolution for the February 1, 2008 amendment of Rule 1110.2 directed AQMD staff to prepare a Technology Assessment including a summary of potential trade-offs between greenhouse gas (GHG) and criteria pollutant emissions due to the adoption of the proposed biogas emission limits (NO<sub>x</sub> limit of 11 ppm (referenced to 15% O<sub>2</sub>), VOC limit of 30 ppm and CO limit of 250 ppm). Operation of the IC engines using biogas to produce electrical power generates the three criteria pollutants NO<sub>x</sub>, VOC and CO. If the operators of those engines elect to cease power generation then the biogas must be flared or redirected to another usage onsite including fueling boilers. The choice to generate power or not leads to a trade-off: upgrade the power generation emissions controls to obtain a cleaner emissions profile or potentially shutdown the internal power generation and flare but in doing so release more greenhouse gases. The following discussion provides a comparison of the impacts the two options present: criteria pollutant emissions and greenhouse gas emissions from operation of the IC engines vs. flaring.

### **Criteria Pollutant Impact**

Figures 11 through 13 compare emissions of criteria pollutants from existing engines, an engine meeting the proposed limits and biogas flares at facilities affected by the proposed biogas emission limits. The range of flare emissions shown in the following figures represents the variety of permit limits and operating conditions for flares at affected facilities. The permit emissions limits vary because the age of flares at these facilities ranges from less than 10 years to 40 years old. The emissions for each technology include the direct emissions from fuel combustion (natural gas). The flare emissions also include the criteria emissions from local utility power plants when biogas is directed to flares instead of being used to generate electricity using IC engines.

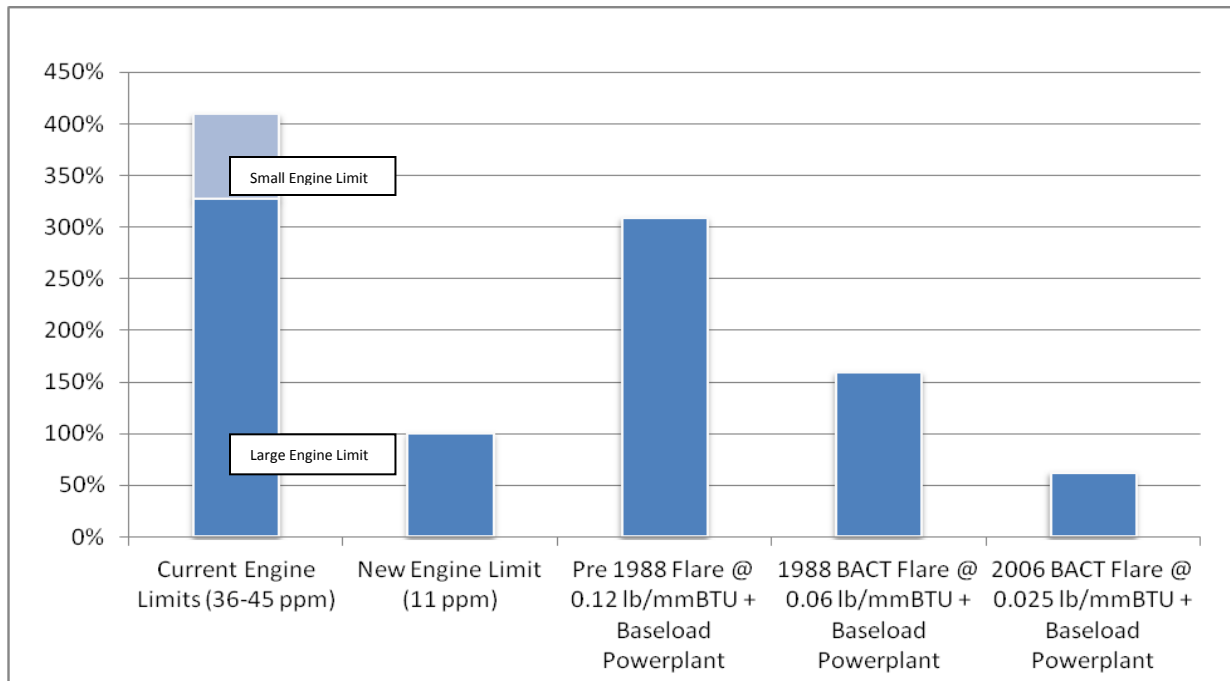
The NO<sub>x</sub>, VOC and CO emissions comparisons depicted in Figures 11 through 13 are expressed as a percent compared to the proposed engine emission limits – a ratio of the

current and proposed emission limits in ppm or pounds of emissions per Btu of fuel consumed. In addition, Figures 11 and 12 show the range of the current NO<sub>x</sub> and VOC emission limits for large and small engines. Also included in the three figures are the estimates of flare emissions and the emissions from a large power plant. These emissions are included because when an engine is shut down, the replacement electricity is assumed to be generated by a local utility boiler or combined cycle turbine.

The comparison of criteria pollutant emissions from engines and flares uses the ratio of the emission limit for the specific technology to the emission factor for an engine meeting the proposed biogas emission limits (NO<sub>x</sub> limit of 11 ppm (referenced to 15% O<sub>2</sub>), VOC limit of 30 ppm and CO limit of 250 ppm). This ratio is then converted to percent with the proposed engine limit set at 100%. This ratio can be generated by converting all emission limits to parts per million at 15% O<sub>2</sub> (the reference level for the Rule 1110.2 emission limits) or by converting all emission limits to pounds per million Btu.

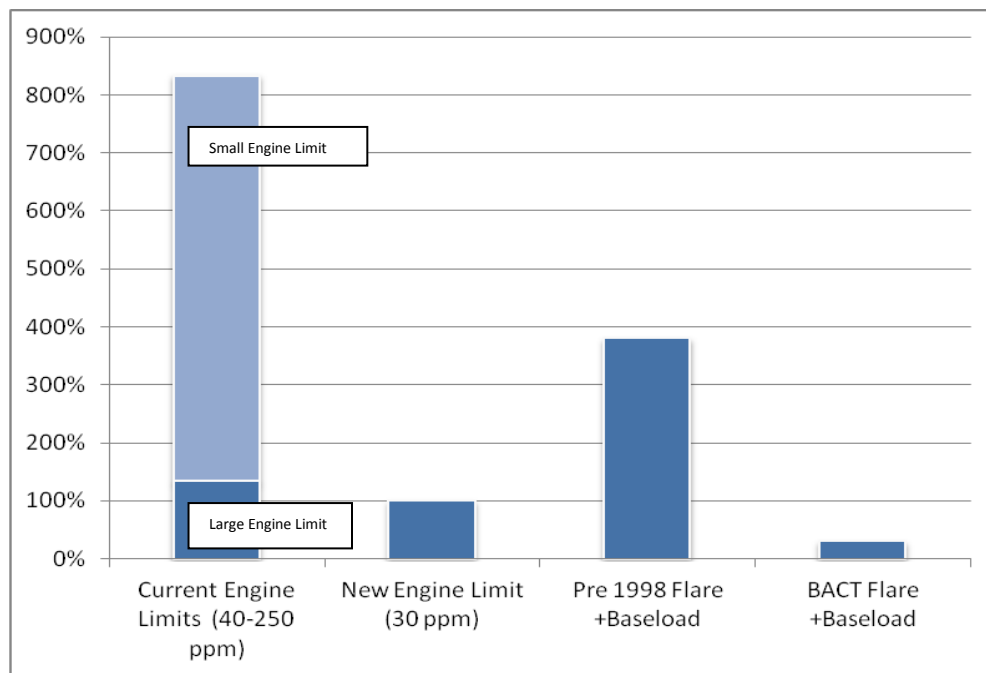
The emission comparisons assume that the biogas is diverted to flares from engines and there is an equivalent amount of electricity produced by local power plants meeting current BACT. Compared to flares, power plant criteria pollutant emissions are smaller because limits are very low and base load power plants use one-half of the fuel of engines to produce the same amount of electricity. These emissions are included in Figures 11 to 13 as part of the flare emissions. While there are other sources of electricity outside the AQMD, the amount of electricity produced by biogas engines is small in comparison and local base load power plants have enough capacity to replace these sources at a cost-effective price.

As presented in the Figures 11 through 13, the option to flare emissions would generate less criteria pollutant emissions than are currently produced under the existing emissions limits, regardless of flare configuration. Operating the IC engines at the proposed limits would be cleaner for NO<sub>x</sub> and VOC than venting emissions to the Pre-1998 flares (which include the required base load emissions). In each case, flaring using a BACT flare, including the base load emissions would generate fewer emissions than for IC engines operating within the proposed new emissions limits. However, the option to flare raises illuminates the counterpoint argument: Does flaring result in a greater GHG emissions impact than generating internal power?



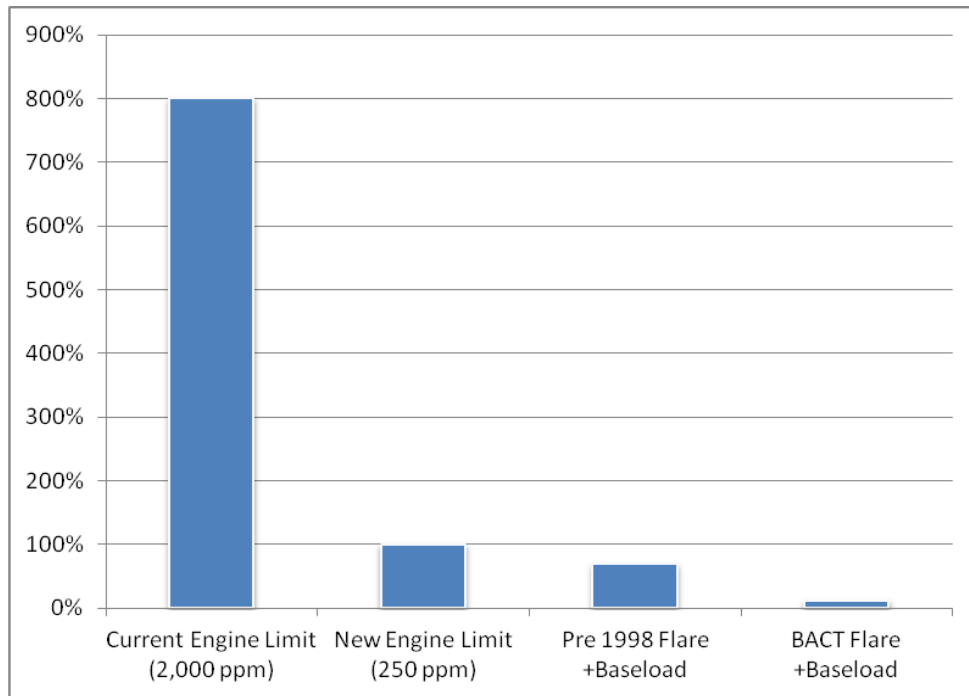
**Figure 11**

### Biogas Flare and Engine NOx Emissions Compared to an 11 PPM Emissions Limit



**Figure 12**

### Biogas Flare and Engine VOC Emissions Compared to a 30 PPM Emissions Limit



**Figure 13**

### **Biogas Flare and Engine CO Emissions Compared to a 250 PPM Emissions Limit**

#### **Greenhouse Gas Impacts**

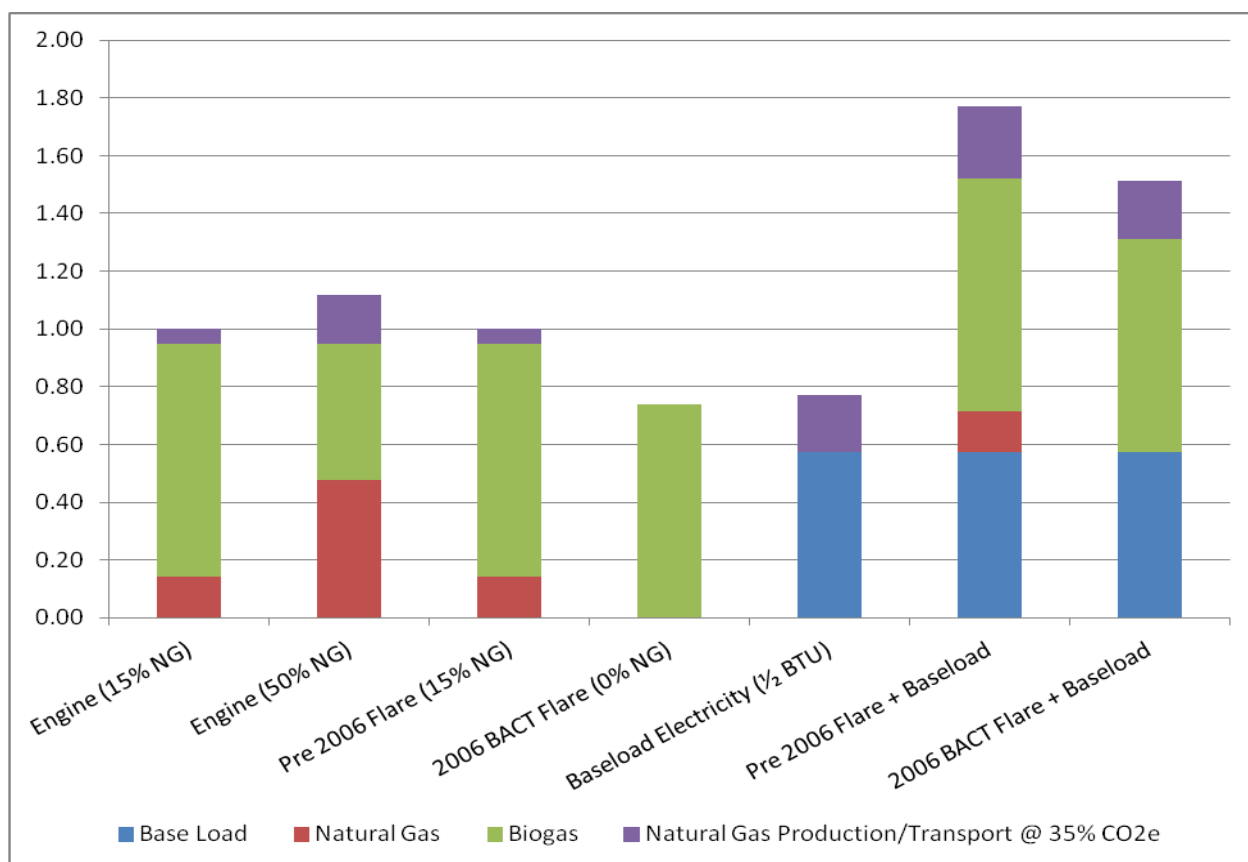
Figure 14 provides a comparison of greenhouse gas emissions impact from engines, flares and base load power generation. The figure includes emissions from engines using different amounts of supplemental fuel (natural gas), power plants and newer versus older flare technologies. The differences in GHG emissions are expressed as percent compared to biogas engine emissions. The GHG emission comparison in Figure 14 is based on carbon dioxide equivalents (CO<sub>2</sub>e). Emissions of gases that contribute to global warming are represented as CO<sub>2</sub> equivalents by taking into account their warming potential in the atmosphere relative to CO<sub>2</sub>. For example, methane (CH<sub>4</sub>) is assigned a warming potential of 21 times CO<sub>2</sub> (over a 100 year timeframe).

More specifically, the comparison of GHG emissions is also a ratio of each technologies emissions (expressed as carbon dioxide equivalents – CO<sub>2</sub>e) to the CO<sub>2</sub>e associated with an IC engine using 15% supplemental natural gas. This ratio is developed on a mass basis. In the case of an IC engine and pre-2006 flare, it is assumed that for every 100 methane molecules provided as fuel to the engine, 99 are combusted to CO<sub>2</sub> and one is emitted in the exhaust. The global warming potential of this one methane molecule is

equivalent to 21 CO<sub>2</sub> molecules. In addition, 15% of the fuel methane for the base engine and pre-2006 flare scenarios comes from natural gas. The 2010 U.S. EPA method for estimating the CO<sub>2</sub>e GHG emissions related from natural gas production and transport to an average of about 20% of the fuel Btu delivered to an operation. In 2011, EPA revised its estimate upwards to average of about 35% of the fuel Btu delivered. Using the 2011 U.S. EPA percentage translates to an additional CO<sub>2</sub>e of 6 more molecules of CO<sub>2</sub> due to production and transport of that natural gas. The summation of these emissions in terms of CO<sub>2</sub> equivalence results in an impact of 126 CO<sub>2</sub> molecules for every 100 molecules of methane provided to the engine.

The same methodology is used to generate the CO<sub>2</sub>e emissions from an engine using 50% supplemental natural gas with the same Btu content, a flare meeting current BACT limits and a base load power plant generating the same amount of electricity as the IC engine (using ½ the Btu of an engine). A flare meeting 2006 BACT has more complete combustion and emits half of the methane than older flares emit and does not require supplemental natural gas. These “emissions” are then used to generate a ratio with the base engine represented as 100%. In this analysis, the electricity is produced by local power plants in order to determine the worst case emissions if engines are replaced with flares.

As depicted in Figure 14, operation of the IC engine using a 15 percent natural gas and 85 percent biogas is equivalent to 126 CO<sub>2</sub> molecules or a factor of 1.0 on the chart. An engine burning 50 percent natural gas has a higher ratio because of the additional production and transport contribution to the total CO<sub>2</sub>e. Using a Pre 2006 (non-BACT) flare with the 15 percent natural gas contribution has an equivalent CO<sub>2</sub>e signature as the biogas engine (1.0). The BACT flare and base load power generation (with the production and transport contribution to the total CO<sub>2</sub>e) exhibit lower GHG impacts compared to the biogas engine or the Pre 2006 flare. However, if a facility elects to flare the gas with a Pre 2006 flare but acquires power from the grid, the factor approaches 1.8 or 80 percent more GHG emissions than continued operation of the IC engine. Even if a facility uses a BACT flare but needs supplemental power from the grid, the factor rises to approximately 1.5 or 50 percent GHG emissions above the continued operation of the IC engine.



**Figure 14**

### **Comparison of CO<sub>2</sub> Equivalent Greenhouse Emissions from Flares and Base Load Electricity and IC Engines**

#### **GHG Impact Summary**

The above analysis provides background assessments of the trade-off between achieving lower criteria pollutant emissions levels from complying with the proposed new standards and the possible GHG emissions penalty which may be incurred if a facility flares but is required to purchase power from the grid. Compared to current biogas engines, flares typically have lower criteria pollutant emissions profiles but have higher emissions of greenhouse gases because electricity must be generated by other sources if the biogas is not used in an engine generating electricity (Table 14).

**Table 14. Comparison of Criteria Pollutant and GHG Impacts from ICE Operating and from Flaring**

Pollutant	Magnitude of Flaring w/BACT Flare + Baseload Compared to ICEs
NO <sub>x</sub>	5x Less
CO	67x Less
VOC	23x Less
GHG (CO <sub>2</sub> e)	1.4x More

Flares meeting current BACT also have a significantly lower greenhouse gas impact compared to older flares. However, new BACT flares still result in about 50% more greenhouse gas emissions than current engines (on a CO<sub>2</sub>e basis).

In general, criteria pollutant impacts have an immediate impact on public health and as such are typically given greatest weight. GHG gas goals set by AB32 and companion legislation target the long term control strategy to address global warming. Both issues have merit and deserve attention. One additional element that needs to be noted is energy conservation and the potential wasting of an available energy source (biogas) which is neither drilled nor mined.

## **CONCLUSION**

The technology demonstration projects have shown that technology is available that can achieve significant reductions in NO<sub>x</sub>, VOC, and CO. Since the 2008 amendment of Rule 1110.2, oxidation catalyst and SCR technology has been effective in reducing pollutant emissions cost effectively for natural gas engines. At the time of the Interim Technology Assessment of 2010, this technology was in the early stages of being explored for the control of biogas engines as well. Since then, the demonstration project at OCSD was successfully completed for the control of biogas emissions from a digester gas facility. In addition, a sufficient amount of data over almost three years was obtained from Ox Mountain Landfill, demonstrating that the control of emissions from a landfill gas-fired engine is achievable on a consistent basis. The utilization of biogas cleanup with siloxane removal has proven essential for the protection of engine components and catalysts. Biogas cleanup systems are currently in use for the protection of engines as

well as microturbines and turbines in the District today. These same systems can also clean the biogas effectively to protect the post-combustion catalytic controls as well.

In addition to catalyst technology, other technologies have emerged as viable alternatives such as the NOxTech system and Hydrogen Injection. Furthermore, technologies such as fuel cells and Flex Energy are viable alternatives for the replacement of IC Engine generated power altogether. The proposed compliance schedule is reasonable, and will allow facilities the needed time to procure, design, and install these systems. Additionally, the compliance schedule will allow enough time for other technologies to be demonstrated and will give facilities more options for compliance.

Alternatives also exist for those facilities, especially landfills, that have closed and whose biogas supply is decreasing below the usable level for IC Engines. In this case, the other alternatives that may be used are boilers, microturbines, or Flex Energy. It is ultimately an operator's decision to flare the biogas, as this also remains as an alternative. However, flaring is still viewed as undesirable due to the pollutant impacts and trade-offs. Cost effective technologies exist that can preclude flaring and still maintain a facility's power-generating capacity with the remaining amount of landfill gas.

The cost effectiveness analysis based on actual data for a digester gas facility shows that the technology is scalable and cost effective for digester gas engines of all sizes. From a dollars per kilowatt standpoint, the analysis shows that the cost of power production will not exceed the cost of purchasing the same power from the grid.

The proposed limits of Rule 1110.2 are feasible and cost effective. Technologies exist today that can achieve these emission limits within the compliance schedule in the Staff proposal. Given the aforementioned cost effective controls and reasonable compliance schedule, increased flaring is not anticipated to occur. On this basis, Staff recommends to move forward with Proposed Amended Rule 1110.2 while maintaining a commitment to continue working with the regulated community in monitoring the performance of ongoing demonstration projects to assure that the compliance schedule is reasonable.

**ATTACHMENT A**

**COST EFFECTIVENESS CALCULATIONS FOR RULE 1110.2  
REQUIREMENTS FOR BIOGAS ENGINES**

---

## Gas Cleanup System + Oxidation Catalyst + SCR (20-year Equipment Life) – Cost basis is OCSD pilot study demonstration

BHP	Digester 4200	Digester 3471	Digester 1600	Digester 1000	Digester 500	Digester 250	Landfill 4200	Landfill 3471	Landfill 2700	Landfill 2000	Landfill 1500
Installed Equipment, \$ (Note 1)	2,240,791	1,989,529	1,230,965	921,665	602,807	395,072	2,345,061	2,082,529	1,781,763	1,479,753	1,239,133
Equipment minus Catalyst, \$	2,102,364	1,875,129	1,178,231	888,707	586,328	386,832	2,206,634	1,968,129	1,692,774	1,413,835	1,189,695
Added Cleanup w/20% contingency (Note 2)	420,473	375,026	235,646	177,741	117,266	77,366	441,327	393,626	338,555	282,767	237,939
Catalyst Cost, \$ (Note 3)	138,427	114,400	52,734	32,959	16,479	8,240	138,427	114,400	88,989	65,918	49,438
<b>Installed Equipment w/20% contingency, \$</b>	<b>2,661,264</b>	<b>2,364,555</b>	<b>1,466,611</b>	<b>1,099,407</b>	<b>720,073</b>	<b>472,438</b>	<b>2,786,388</b>	<b>2,476,155</b>	<b>2,120,318</b>	<b>1,762,520</b>	<b>1,477,072</b>
Project Management & Installation Supervision, \$ (Note 4)	361,107	298,429	137,565	85,978	42,989	21,494	361,107	298,429	232,140	171,956	128,967
<b>Total Initial Investment, \$</b>	<b>3,022,371</b>	<b>2,662,984</b>	<b>1,604,176</b>	<b>1,185,384</b>	<b>763,062</b>	<b>493,933</b>	<b>3,147,495</b>	<b>2,774,584</b>	<b>2,352,458</b>	<b>1,934,475</b>	<b>1,606,039</b>
Sorbent Replacement, \$/yr (Note 5)	165,600	138,000	69,000	103,500	51,570	12,420	276,000	276,000	138,000	207,000	103,500
Catalyst Replacement, \$/yr (every 2yr, Note 6)	69,213	57,200	26,367	16,479	8,240	4,120	69,213	57,200	44,494	32,959	24,719
Reactant, \$/yr (Note 7)	22,869	18,900	8,712	5,445	2,723	1,361	22,869	18,900	14,702	10,890	8,168
Reduced Power Production, \$/yr (Note 8)	2,859	1,200	1,089	681	340	170	1,664	1,200	1,069	792	594
Equipment Maintenance, \$/yr (Note 9)	-36,479	-30,147	-13,897	-8,685	-4,343	-2,171	-36,479	-30,147	-23,451	-17,371	-13,028
<b>Total Annual Cost, \$</b>	<b>224,064</b>	<b>185,153</b>	<b>91,272</b>	<b>117,420</b>	<b>58,530</b>	<b>15,900</b>	<b>333,268</b>	<b>323,153</b>	<b>174,815</b>	<b>234,270</b>	<b>123,953</b>
<b>Present Value of 20-yr Cost, \$ (Note 10)</b>	<b>6,067,395</b>	<b>5,179,213</b>	<b>2,844,560</b>	<b>2,781,121</b>	<b>1,558,484</b>	<b>710,013</b>	<b>7,676,607</b>	<b>7,166,233</b>	<b>4,728,196</b>	<b>5,118,211</b>	<b>3,290,558</b>
NOx Reduction, tpy (Note 11)	12.6	10.5	4.8	3	1.5	1	12.6	10.5	8.1	6	4.5
VOC Reduction, tpy (Note 11)	29	24	11.1	6.9	3.5	1.7	1.3	1.1	0.8	0.6	0.5
CO Reduction, tpy (Note 11)	538.9	445.4	205.3	128.3	64.2	32.1	538.9	445.4	346.4	256.6	192.5
CO Reduction/7, tpy (Note 12)	77.0	63.6	29.3	18.3	9.2	4.6	77.0	63.6	49.5	36.7	27.5
<b>Cost Effectiveness, \$ per ton of NOx+VOC+CO/7</b>	<b>2600</b>	<b>2600</b>	<b>3100</b>	<b>4900</b>	<b>5500</b>	<b>4900</b>	<b>4200</b>	<b>4800</b>	<b>4000</b>	<b>5900</b>	<b>5100</b>
<b>\$/kW-hr</b>	<b>0.012</b>	<b>0.013</b>	<b>0.015</b>	<b>0.024</b>	<b>0.027</b>	<b>0.025</b>	<b>0.016</b>	<b>0.018</b>	<b>0.015</b>	<b>0.022</b>	<b>0.019</b>

### Notes for Gas Cleanup + Oxidation Catalyst + SCR:

1	From the OCSD Final Report for a 3,471 bhp engine, the construction subtotal for equipment and labor with contractor contingencies included is \$1,989,529.
	The non-catalyst installed cost is assumed to vary with $\text{bhp}^{0.6}$ based on general chemical engineering cost estimating practice for tanks and reactors.
	For landfills, the installed cost of the siloxane removal system is higher because of the higher gas volume per BTU supplied to the engine. Additional cost for gas cleanup on a 3,471 bhp engine is \$93,000.
2	A 20% contingency to account for possible additional gas cleanup equipment is added to the equipment costs minus catalyst
3	For the OCSD catalysts, there were 16 catalytic oxidizer blocks at \$3,450 per block and thirty-two SCR catalyst blocks at \$1,850 per block.
	Catalyst cost is assumed to vary directly with bhp.
4	Cost for project management and installation supervision for OCSD was calculated as a 15% contingency of the installed equipment costs, not including the 20% contingency accounting for possible additional gas cleanup equipment.
5	Vender quotes were obtained for non-regenerative activated carbon vessels/media and were sized and bracketed according to flow rate. Change-out frequency is once every month. The total cost for the media replacement was divided by the number of engines per facility to arrive at a per engine cost. The highest cost at each bracketed engine size was used.
	OCSD's media replacement cost from the pilot study was \$40,000 for one year on a 3,471 engine.
6	OCSD experienced a partial deactivation of its oxidation catalyst after two years of operation. Staff has accounted for this by using the annual cost for a biannual catalyst replacement.
7	Cost of urea is based on OCSD's annual cost. Reactant cost is assumed to vary directly with horsepower.
8	Pressure drops across the siloxane removal and SCR systems are assumed to be 3" H <sub>2</sub> O each. Calculated reduction in power production is 0.147%.
	Cost of reduced power is: $\text{bhp} \times 0.00147 \times 8,000 \text{ hrs/yr} \times 0.746 \text{ kW/bhp} \times 0.97 \text{ generator efficiency (kWh/yr)}$
	For landfill gas the power reduction is 0.161% because the higher volume of landfill gas per BTU supplied to the engine. Cost of power is \$0.08/kWh for digester gas (cost of grid power) and \$0.0425/kWh for landfill gas power (typical wholesale price based on price SCE paid for power from El Sobrante landfill [2002 contract]).
	Electrical costs for OCSD's pilot study were \$1,200/yr.
9	OCSD's reduced engine maintenance was subtracted from its equipment maintenance for the pilot study. This cost is assumed to vary directly with horsepower.
10	The present worth value (PWV) is calculated for a project life of 20 years at an interest rate of 4%.
11	Baseline NO <sub>x</sub> is 36 ppmvd corrected to 15% O <sub>2</sub> for engines equal to or greater than 500 bhp and 45 ppmvd corrected to 15% O <sub>2</sub> for engines smaller than 500 bhp.
	Baseline VOC is 40 ppmvd corrected to 15% O <sub>2</sub> for landfill gas engines and 250 ppmvd corrected to 15% O <sub>2</sub> for digester gas engines.
	Baseline CO is 2000 ppmvd corrected to 15% O <sub>2</sub> .
	Conversion of ppmvd corrected to 15% O <sub>2</sub> to g/bhp-hr was based on an engine efficiency of 33% (based on higher heating value), which was the average for biogas engines in the engine survey conducted for the 2008 amendment. This includes a correction of 3% greater volume of combustion products (corrected to 15% O <sub>2</sub> ) due to the CO <sub>2</sub> in the fuel.
	The emission reduction calculations assume 8,000 hrs/yr of engine operation.
12	The CO reductions are discounted by 1/7 due to its reduced ozone formation potential.

## **NOxTech System (20-year Equipment Life) – Costs provided by NOxTech**

	Digester	Digester	Digester	Digester	Digester	Digester	Digester	Landfill	Landfill	Landfill	Landfill	Landfill	Landfill
BHP	4200	3471	1600	1350	1000	500	250	4200	3471	2700	2000	1500	1350
<b>Installed Equipment, \$</b>													
<i>Equipment Cost, \$ (Note 1)</i>	960,000	800,000	400,000	400,000	400,000	400,000	400,000	960,000	800,000	800,000	400,000	400,000	400,000
<i>Installation Cost, \$ (Note 2)</i>	250,000	200,000	100,000	100,000	100,000	100,000	100,000	250,000	200,000	200,000	100,000	100,000	100,000
<i>Installation Cost Contingency, \$ (Note 3)</i>	300,000	300,000	300,000	300,000	300,000	300,000	300,000	0	0	0	0	0	0
Project Management & Installation Supervision, \$ (Note 4)	31,742	26,452	13,226	13,226	13,226	13,226	13,226	31,742	26,452	26,452	13,226	13,226	13,226
<b>Total Initial Investment, \$</b>	<b>1,541,742</b>	<b>1,326,452</b>	<b>813,226</b>	<b>813,226</b>	<b>813,226</b>	<b>813,226</b>	<b>813,226</b>	<b>1,241,742</b>	<b>1,026,452</b>	<b>1,026,452</b>	<b>513,226</b>	<b>513,226</b>	<b>513,226</b>
Reactant, \$/yr (Note 5)	37,952	31,365	14,458	12,199	9,036	4,518	2,259	37,952	31,365	24,398	18,073	13,554	12,199
Reduced Power Production, \$/yr (Note 6)	68,365	56,499	26,044	21,975	16,277	8,139	4,069	53,041	43,834	34,098	25,258	18,943	17,049
Equipment Maintenance, \$/yr (Note 7)	16,000	16,000	8,100	8,100	8,100	8,100	8,100	16,000	16,000	16,000	8,100	8,100	8,100
<b>Total Annual Cost, \$</b>	<b>122,318</b>	<b>103,864</b>	<b>48,602</b>	<b>42,274</b>	<b>33,414</b>	<b>20,757</b>	<b>14,428</b>	<b>106,993</b>	<b>91,199</b>	<b>74,496</b>	<b>51,430</b>	<b>40,598</b>	<b>37,348</b>
<b>Present Value of 20-yr Cost, \$ (Note 8)</b>	<b>3,204,042</b>	<b>2,737,965</b>	<b>1,473,728</b>	<b>1,387,724</b>	<b>1,267,319</b>	<b>1,095,312</b>	<b>1,009,308</b>	<b>2,695,780</b>	<b>2,265,852</b>	<b>2,038,847</b>	<b>1,212,161</b>	<b>1,064,947</b>	<b>1,020,783</b>
NOx Reduction, tpy (Note 9)	12.6	10.5	4.8	4.1	3	1.5	1	12.6	10.5	8.1	6	4.5	4.1
VOC Reduction, tpy (Note 9)	29	24	11.1	9.3	6.9	3.5	1.7	1.3	1.1	0.8	0.6	0.5	0.4
CO Reduction, tpy (Note 9)	538.9	445.4	205.3	173.2	128.3	64.2	32.1	538.9	445.4	346.4	256.6	192.5	173.2
CO Reduction/7, tpy (Note 10)	77.0	63.6	29.3	24.7	18.3	9.2	4.6	77.0	63.6	49.5	36.7	27.5	24.7
<b>Cost Effectiveness, \$ per ton of NOx+VOC+CO/7</b>	<b>1400</b>	<b>1400</b>	<b>1600</b>	<b>1800</b>	<b>2200</b>	<b>3900</b>	<b>6900</b>	<b>1500</b>	<b>1500</b>	<b>1700</b>	<b>1400</b>	<b>1600</b>	<b>1700</b>
<b>\$/kW-hr</b>	<b>0.007</b>	<b>0.007</b>	<b>0.008</b>	<b>0.009</b>	<b>0.011</b>	<b>0.019</b>	<b>0.035</b>	<b>0.006</b>	<b>0.006</b>	<b>0.007</b>	<b>0.005</b>	<b>0.006</b>	<b>0.007</b>

### Notes for NOxTech System:

1	NOxTech provided the following cost information:
	Equipment cost for NOxTech unit sized for 1 engine at 1.5 MW max rating = \$400,000. 2 units are required for engines greater than 1.5 MW and less than 3 MW = \$800,000. A discount is offered for 3 or more units purchased simultaneously = \$960,000 for engines greater than 3 MW.
	If a single unit treats multiple engines with a maximum total rating of 1.5 MW, the cost is \$450,000.
	These installation costs are “turn-key.” They are site-specific and depend on many factors. The installation costs provided by NOxTech are intended to be typical.
2	Installation costs, including urea tank, are \$100,000 for 1 unit treating 1 engine up to 1.5 MW, \$200,000 for 2 units treating engines greater than 1.5 MW and less than 3 MW, and \$250,000 for 3 units treating engines greater than 3 MW.
	For a single unit treating multiple engines with a maximum total rating of 1.5 MW, the cost is \$150,000.
3	EMWD’s installation costs were \$400,000 for the EGR system. There were also additional equipment and design costs reported that may be site-specific, depending on operating characteristics. The added engineering costs are not independently verifiable. As part of the demonstration project, EMWD incurred added design costs that are not anticipated to be included as a part of future off-the-shelf technology. The additional costs are presented here merely as a worst case and are not expected to be incurred by future end users. The added EGR costs do not apply to landfills because there is no expected natural gas supplementation that would necessitate an EGR system.
4	Project management and installation supervision is assumed to be the same ratio to non-catalyst installed equipment as the OCSD project. For the Interim Technology Assessment, this cost was estimated to be \$36,000 for OCSD labor for project management and installation supervision of \$1,096,000 of non-catalyst equipment cost. For OCSD’s actual non-catalyst equipment cost, which was \$1,875,129, the project management and installation supervision cost is approximately \$62,000.
5	Reactant is urea. Stoichiometry is 1 pound of urea to treat 1 pound of NOx. Cost of urea is \$1.50 per gallon based on information provided by NOxTech. Reactant cost is assumed to vary directly with horsepower.
6	Reduction in power production is caused by biogas use in NOxTech reactor and pressure drop across NOxTech system. Fuel use is assumed to be 5% of full-load engine fuel, and pressure drop is assumed to be 3”H2O. Calculated reduction in power production is 0.133%.
	Reduced power output is: $\text{bhp} \times 0.746 \text{ kW/bhp} \times 8,000 \text{ hrs/yr} \times 0.00133 \times 0.97 \text{ generator efficiency (kWh/yr)}$ .
	It is assumed that use of 5% of full-load engine fuel in NOxTech chamber further reduces power by 5% in landfill gas case, but digester gas can be replaced by natural gas.
	Cost of reduced power is \$0.08/kWh for digester gas case and \$0.0425/kWh for landfill gas case. Cost of natural gas is \$0.50 per them.
7	Information provided by NOxTech: annual maintenance for 1 NOxTech unit is estimated to be \$8,100 and \$16,000 for 2 or more units. The annual maintenance cost for 1 unit treating multiple engines with a maximum total rating of 1.5 MW is \$10,000.
8	Same as Note 10 in previous table.
9	Same as Note 11 in previous table.
10	Same as Note 12 in previous table.

## REFERENCES

---

1. Orange County Sanitation District, *Catalytic Oxidizer Pilot Study*, Report to AQMD, August 2007
2. Orange County Sanitation District, *Retrofit Digester Gas Engine with Fuel Gas Clean-up and Exhaust Emission Control Technology*, Final Report to AQMD, July 2011
3. SCAQMD, 2008. *Staff Report: Proposed Amended Rule 1110.2 - Emissions From Gaseous- and Liquid-Fueled Engines*. South Coast Air Quality Management District, February 2008
4. SCAQMD, 2008. *Staff Report: Proposed Amended Rule 1110.2 - Emissions From Gaseous- and Liquid-Fueled Engines*. South Coast Air Quality Management District, February 2008, Appendix D
5. E. Wheless, D. Gary, *Siloxanes in Landfill and Digester Gas*, Proceedings of Solid Waste Association of North America (SWANA) Landfill Gas Symposium, March 2002
6. SCAQMD, 2010. *Interim Report on Technology Assessment for Biogas Engines Subject to Rule 1110.2*. South Coast Air Quality Management District, July, 2010
7. E.P.A, *Compilation of Air Pollutant Emission Factors (AP-42, Volume 1, Stationary Point and Area Sources)*, <http://www.epa.gov/ttnchie1/ap42/>, accessed February 10, 2012
8. Mark Fulton, Nils Mellquist, Saya Kitasei, and Joel Bluestein, *Comparing Life-Cycle Greenhouse Emissions from Natural Gas and Coal*, Deutsche Bank Group, Worldwatch Institute and ICF International (August 25, 2011), [http://www.worldwatch.org/system/files/pdf/Natural\\_Gas\\_LCA\\_Update\\_082511.pdf](http://www.worldwatch.org/system/files/pdf/Natural_Gas_LCA_Update_082511.pdf), accessed February 10, 2012
9. SCAQMD, *BACT Guidelines*, <http://www.aqmd.gov/bact/index.html>, accessed February 10, 2012
10. Financial Energy Management, Inc, *Reciprocating Combustion Engine and Generator Set*, <http://www.financialenergy.com/services/generator/types.htm>, accessed March 2012.
11. California Public Utilities Commission, *Self-Generation Incentive Program Handbook*, October 10, 2011, <http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/>.